THREE MOUNTAIN POWER PROJECT
EXECUTIVE SUMMARY

INTRODUCTION

This Final Staff Assessment (FSA) Part 2 contains the California Energy Commission (Energy Commission) staff's evaluation of the Three Mountain Power, LLC's (the applicant) Application for Certification (AFC) (99-AFC-2) for the Three Mountain Power Project (TMPP). The topic areas addressed in Part 2 include: project description, air quality, land use, noise, power plant efficiency, power plant reliability, public health, visual resources, and waste management. Part 3 will be published on November 15, 2000, and will address Biological Resources, Soil & Water Resources and alternatives. Other issues were address in Part 1 of the FSA, published on January 24, 2000.

The TMPP electric generating plant and related facilities, such as the electric transmission line, natural gas pipeline and water lines, are under the Energy Commission's jurisdiction and cannot be constructed or operated without the Energy Commission's certification.

Staff is an independent party in the proceedings. This FSA contains staff's independent analysis of engineering and environmental aspects of the TMPP, based on the information available at that time of document creation. These analyses are similar to those contained in an Environmental Impact Report required by the California Environmental Quality Act (CEQA). It is important to note that the FSA is not a Committee document nor is it a final or proposed decision on the proposal. The FSA presents staff's testimony and contains conclusions and proposed conditions that staff recommends apply to the design, construction, operation, and closure of the proposed facility, if certified.

BACKGROUND

On March 3, 1999, the applicant filed an AFC with the Energy Commission to construct and operate the TMPP. On April 14, 1999, the Energy Commission determined that the application should not be accepted due to data inadequacies. On June 4, 1999, the applicant filed supplemental information to address the list of data inadequacies adopted by the Energy Commission. The Energy Commission deemed the application complete at its June 23, 1999 business meeting. The analyses contained in this FSA are based upon information from: 1) the AFC; 2) subsequent amendments; 3) responses to data requests; 4) supplementary information from local and state agencies and interested individuals; 5) existing documents and publications; and 6) independent field studies and research.

PROJECT DESCRIPTION

The TMPP will be located in northeastern Shasta County, approximately one mile northeast of Burney, California, and 45 miles east of Redding, California. The site is located on a 40-acre site that is zoned for industrial use. Approximately one-third of the site is currently developed and used by Burney Mountain Power, LLC, which operates a 10 megawatt (MW) biomass-fueled power plant. The site is located on State Route 299, northeast of Black Ranch Road between the towns of Burney and Johnson Park, (Township 35 North, Range 3 East, on Assessor's Parcel Number 030-390-36). See **PROJECT DESCRIPTION** Figures 1 and 2 for the location of the project.

The 500 MW nominal rated combined cycle design will consist of two "F" class combustion turbines (170 MW each), two heat recovery steam generators (HRSG) and one steam turbine (up to 230 MW). The applicant is currently considering two manufacturers for the "F" class combustion turbines: General Electric and Westinghouse. The combined cycle configuration will incorporate water treatment equipment, air compressor, inlet air evaporative coolers, turbine and generator set, continuous emission monitors, control room and administrative building, step-transformers, heat recovery steam generators, a steam turbine, two 140 foot exhaust stacks, a hybrid cooling system (consisting of both wet and dry cooling towers), selective catalytic reduction (SCR) and aqueous ammonia storage and handling equipment. The SCR and ammonia are used to reduce nitrogen oxide (NOx) emissions. The SCR and dry low NOx combustion technology will reduce NOx emissions from the combined cycle configurations to 2.5 ppmvd, or less, at 15 percent oxygen. The heat recovery steam generators are used to recover waste heat from the combustion turbine exhaust to produce steam. This steam is then expanded in the steam turbine to produce electricity. The project is expected to have an overall availability of 95 percent and to operate up to 8,760 hours per year.

The project consists of a power island, administrative buildings, chemical storage areas, cooling tower and other support facilities. Natural gas will be supplied to the project via a new 12-inch pipeline connection with Pacific Gas and Electric Company's (PG&E) natural gas pipeline located southeast of the project site. The applicant has identified three alternative routes for the natural gas pipeline connection. The applicant's September 2, 1999 response to staff's data request 16 indicated that route A will be used. This route calls for a 2,900 foot connection.

The cooling water utilized by TMPP will come from three sources: a) fresh groundwater will be pumped by the Burney Water District (BWD) from two new wells; b) displaced water use from Burney Mountain Power (BMP), which will be achieved by retrofitting the BMP facility with a hybrid cooling system and/or reducing operating of the BMP facility; and c) if contractual agreements can be reached with the BWD, treated wastewater will be provided by BWD from the wastewater treatment adjacent to the proposed project site.

The applicant will use no more than 600 acre-feet per year of groundwater that historically has not been used for power plant cooling. This is groundwater that will be pumped by BWD from two new wells. The Burney Water District will construct approximately 3,000 feet of new 14-inch inch pipeline to connect new wells to the Burney Water District storage tank and construct a new 4,700 foot 24-inch pipeline from the new wells to the project site. The applicant can increase its use of groundwater beyond the 600 acre-feet per year of new water, by up to 350 acre-feet per year, by using groundwater that the BMP Facility historically has used for cooling water purposes. This is due to the fact that historically BMP has used approximately 350 acre-feet of groundwater per year from a BMP well located adjacent to the BMP Facility. Pursuant to the Detailed Mitigation Plan[1], the 350 acre-feet currently used by BMP will now be shared between BMP and TMPP. The BMP facility will be retrofitted with a hybrid cooling water system or BMP will reduce its operations or both to reduce its water use.

As part of the Detailed Mitigation Plan, the applicant has agreed to enter into negotiations with BWD to: a) upgrade BWD's Wastewater Treatment Plant ("WWTP") to meet California Department of Health Services (DHS) standards for Disinfected Tertiary Recycled Water, b) obtain DHS and other regulatory approvals for the upgrade, and c) provide any wastewater produced by the upgraded WWTP ("Reclaimed Water") to TMPP for cooling purposes**. If these negotiations are successful**, the applicant intends to use the Reclaimed Water for cooling the TMPP.

A new PG&E switchyard will be located on the project site. The line connecting the TMPP facility to PG&E's switchyard will be a 230 kV single circuit transmission line. The tie-in with the existing PG&E 230 kV Pit River hydro transmission line is approximately 800 feet west and then 1800 feet in a northerly direction adjacent to the McCloud River Railroad easement. The Pit #1-Pit #3 230 kV transmission circuit and the Pit #1-Cottonwood 230 kV transmission circuit will be intersected and looped to the new PG&E switchyard. To accommodate the TMPP power output, 60 lineal miles of reconductoring[2] utilizing existing towers to the Round Mountain and Cottonwood substations is proposed. These transmission lines are shown on **PROJECT DESCRIPTION** Figure 1.

The project is estimated to have a capital cost of about $250 million. The applicant plans to complete construction and start operation of the TMPP by the second quarter of 2002. During construction, an average of approximately 200 workers would be employed. During operation, the TMPP would employ 20 to 25 full-time staff.

STAFF'S ASSESSMENT

Each technical area section of the FSA contains a discussion of impacts, mitigation measures and conditions of certification. The FSA includes staff's assessments of:

- the environmental setting of the proposal;
- impacts on public health and safety, and measures proposed to mitigate these impacts;
- environmental impacts, and measures proposed to mitigate these impacts;

[1] "Detailed Mitigation Plan and Analysis of Impact Assessments In Resource Areas Affected by the Mitigation Plan", August 21, 2000.

[2] "Reconductoring" consists of removing the old insulators, installing new insulators and replacing the old conductors with new conductors with a higher capacity.

- the engineering design of the proposed facility, and engineering measures proposed to ensure the project can be constructed and operated safely and reliably;
- project closure;
- project alternatives;
- compliance of the project with all applicable laws, ordinances, regulations and standards (LORS) during construction and operation; and
- proposed conditions of certification.

CHAPTER 1 ANALYSES

Staff's FSA Part 1 published on January 24, 2000 consisted of the following 19 technical areas:

Need Conformance	Socioeconomics
Public Health	Waste Management
Hazardous Materials Handling	Geology and Paleontology
Transmission Line Safety & Nuisance	Facility Design
Land Use	Reliability
Traffic and Transportation	Efficiency
Noise	Transmission System Engineering
Visual Resources	General Conditions/Compliance
Cultural Resources	Worker Safety and Fire Protection
Biological Resources	

Hearings were conducted on all of these topics except Biological Resources, Noise, and Public Health. On August 21, 2000, the applicant filed its "Detailed Mitigation Plan and Analysis of Impact Assessments In Resource Areas Affected by the Mitigation Plan" (Detailed Mitigation Plan). The Detailed Mitigation Plan affects staff's analysis in a number of topic areas, which will require that the record for some topic areas will need to be reopened, and for other areas, staff will need to revise its analysis to reflect these changes. Those areas are:

Topic Areas for Which the Evidentiary Record will Need to be Reopened	Topic Areas not yet heard, that will Require New or Additional Analysis
Project Description[3]	Air Quality
Land Use	Public Health[3]
Visual Resources	Biological Resources[3]
Waste Management	Soils & Water Resources
Power Plant Efficiency	Noise[3]

[3] Staff's testimony on the project description, public health, noise and biological resources was contained the FSA Part 1. Staff will revised its testimony for these topics to reflect the Detailed Mitigation Plan. The testimonies in these areas from the January 2000 FSA Part 1 should be replace in total with the testimonies in FSA Parts 2 and 3.

This FSA Part 2 contains staff analysis of the proposed project (including staff review of the Detailed Mitigation Plan) for all of the above topic areas except Biological Resources, Soil & Water Resources and Alternatives, which will be published on November 15, 2000.

STAFF RECOMMENDATION

Since staff has not completed its analyses for Soil & Water Resources, Biological Resources and Alternatives we believe it is premature to tender any recommendations on the Three Mountain Power Project.

THREE MOUNTAIN POWER PROJECT (99-AFC-2)
FINAL STAFF ASSESSMENT PART 2

PROJECT DESCRIPTION

Prepared by Richard K. Buell

NATURE AND PURPOSE OF PROJECT

The Three Mountain Power Project, Limited Liability Company (applicant) proposes to construct and operate the 500 megawatt (MW) Three Mountain Power Project (TMPP) natural gas fueled electricity generation power plant. Electrical energy produced from the proposed merchant power plant will be sold in California's newly restructured electricity market. The applicant's stated objectives for the project are to:

1. Expedite construction and operation schedules by using an existing site under applicant's control.
2. Use a readily available, secure water supply for the facility's cooling water, and a readily available means of handling wastewater discharge.
3. Use a site with appropriate geological conditions, including geotechnical compatibility and consideration of local floodplain characteristics.
4. Maximize compatibility with existing land use and zoning.
5. Maximize local community acceptability with consideration of noise, public health, worker safety, and hazardous materials handling issues.
6. Maximize the project's ability to meet air quality requirements.
7. Minimize the miles of new transmission line construction required to connect with the existing Pacific Gas and Electric (PG&E) 230 kilovolt (kV) transmission line
8. Minimize the construction distance of the natural gas tie-in line to the PG&E natural gas transmission line.
9. Minimize the project's visibility and impacts on visual resources.
10. Minimize the impact on endangered species and their habitats.
11. Minimize the impact on cultural resources.

PROJECT LOCATION

The TMPP will be located in northeastern Shasta County, approximately one mile northeast of Burney, California, and 45 miles east of Redding, California. The site is located on a 40-acre site that is zoned for industrial use. Approximately one-third of the site is currently developed and used by Burney Mountain Power, LLC, which operates a 10 megawatt (MW) biomass-fueled power plant. The site is located on State Route 299 northeast of Black Ranch Road between the towns of Burney and Johnson Park, (Township 35 North, Range 3 East, on Assessor's Parcel Number 030-390-36). See **PROJECT DESCRIPTION** Figures 1 and 2 for the location of the project.

PROJECT DESCRIPTION Figure 1
Regional Setting

PROJECT DESCRIPTION Figure 2

Local Setting

PROJECT DESCRIPTION

PROJECT DESCRIPTION Figure 3 shows the proposed equipment layout for the project. The 500 MW nominal rated combined cycle design will consist of two "F" class combustion turbines (170 MW each), two heat recovery steam generators (HRSG) and one steam turbine (up to 230 MW). The applicant is currently considering two manufacturers for the "F" class combustion turbines: General Electric and Westinghouse. The combined cycle configuration will incorporate water treatment equipment, air compressor, inlet air evaporative coolers, turbine and generator set, continuous emission monitors, control room and administrative building, step-transformers, heat recovery steam generators, a steam turbine, two 140 foot exhaust stacks, a hybrid cooling system (consisting of both wet and dry cooling towers), selective catalytic reduction (SCR) and aqueous ammonia storage and handling equipment. The SCR and ammonia are used to reduce nitrogen oxide (NOx) emissions. The SCR and dry low NOx combustion technology will reduce NOx emissions from the combined cycle configurations to 2.5 ppmvd, or less, at 15 percent oxygen. The heat recovery steam generators are used to recover waste heat from the combustion turbine exhaust to produce steam. This steam is then expanded in the steam turbine to produce electricity. The project is expected to have an overall availability of 95 percent and to operate up to 8,760 hours per year.

WATER SUPPLY

The cooling water utilized by TMPP will come from three sources: a) fresh groundwater will be pumped by the Burney Water District (BWD) from two new wells; b) displaced water use from Burney Mountain Power (BMP), which will be achieved by retrofitting the BMP facility with a hybrid cooling system and/or reducing operating of the BMP facility; and c) if contractual agreements can be reached with the BWD, treated wastewater will be provided by BWD from the wastewater treatment adjacent to the proposed project site.

LIMITATION ON NEW WATER USE

The applicant will use no more than 600 acre-feet per year of groundwater that historically has not been used for power plant cooling. This is groundwater that will be pumped by BWD from two new wells. BWD will also install approximately 4,700 ft of new 24 inch water line between the new wells and the TMPP property line to provide this new water to TMPP. The proposed water lines are shown on **PROJECT DESCRIPTION** Figure 2. Location of the wells and the water supply for the project are discussed in the **Soil and Water Resources** section of Part 2b of the FSA, to be published on November 15, 2000.

BURNEY MOUNTAIN POWER (BMP) WATER USE

The applicant can increase its use of groundwater beyond the 600 acre-feet per year of New Water, by up to 350 acre-feet per year, by using groundwater that the BMP Facility historically has used for cooling water purposes. This is due to the fact that historically, BMP has used approximately 350 acre-feet of groundwater per year from a BMP well located adjacent to the BMP Facility. Pursuant to the

Detailed Mitigation Plan[1], the 350 acre-feet currently be used by BMP will now be shared between BMP and TMPP. The BMP facility will be retrofitted with a hybrid cooling water system or BMP will reduce its operations or both to reduce its water use. If ground water consumption is not reduced from the BMP facility, the ground water available to the TMPP project will not be increased above 600 acre-feet per year.

Because there will not be a water line between the existing BMP well and the TMPP Facility, TMPP will not be able to use the existing BMP well. Accordingly, all fresh groundwater used by TMPP, including its portion of BMP Water, will come from the new BWD wells through the 4,700 ft. new 24 inch pipeline to the TMPP property line and through the new BWD water. However, any portion of the 350 acre-feet of BMP water that is used by BMP will continue to come from the existing BMP well.

CONFIRMATION OF GROUNDWATER USE LIMITATIONS

All new water and BMP Water used by TMPP will be metered by BWD. BWD will install a water meter where the new 24 inch water line crosses the TMPP property line. BWD will issue a monthly invoice to TMPP stating how much groundwater TMPP has used the previous month. BMP will install a water meter on its existing well and will give a statement of its monthly water usage to TMP.

RECLAIMED WATER

As part of the Joint Mitigation Plan, the applicant has agreed to enter into negotiations with BWD to: a) upgrade BWD's Wastewater Treatment Plant ("WWTP") to meet California Department of Health Services (DHS) standards for Disinfected Tertiary Recycled Water, b) obtain DHS and other regulatory approvals for the upgrade, and c) provide any wastewater produced by the upgraded WWTP ("Reclaimed Water") to TMPP for cooling purposes**. If these negotiations are successful**, the applicant intends to use the Reclaimed Water for cooling the TMPP.

Verification:

Based on the WWTP's existing permit, its discharge limitation is 0.44 million gallons per day. TMPP will agree to fund the design and construction of a WWTP upgrade that is compatible with the currently permitted capacity. All equipment associated with the upgrade will be on disturbed BWD property that is adjacent to the TMPP property. There is sufficient space available to install the required new equipment on the BWP property. Because the area is already disturbed, no biological or cultural assessment was required.

The TMPP will take all the Reclaimed Water that is available and otherwise acceptable from the upgraded WWTP. The Reclaimed Water will be piped directly, through a BWD Reclaimed Water meter, to the TMPP cooling tower basin. Because TMPP will have no capability to store Reclaimed Water, when TMPP is not operating or the upgraded WWTP is producing more Reclaimed Water than TMPP

[1] "Detailed Mitigation Plan and Analysis of Impact Assessments In Resource Areas Affected by the Mitigation Plan", August 21, 2000.

is able to use, the Reclaimed Water will be diverted to the existing BWD percolation ponds. In addition, TMPP will not accept Reclaimed Water from BWD when it does not meet DHS standards, which water also would be diverted to the existing percolation ponds.

Reclaimed Water Metering

BWD's WWTP is located adjacent to the TMPP property. BWD will install a pipeline to the WWTP property line. The exact location of this pipeline within BWD property will not be known until BWD completes its design of the upgraded WWTP. TMPP will continue this pipeline inside TMPP property to the cooling tower basin. All areas within BWD property is disturbed and TMPP property has been assessed for biological or cultural resources, therefore no additional assessment is required. BWD will install a water meter that, on a monthly basis, measures the flow of Reclaimed Water to TMPP.

Operational Use of Reclaimed Water

There will be a 500,000 gallon fresh water storage tank located on the TMPP property. This tank will store only groundwater that is received through the BWD 24 inch pipeline and BWD water meter (i.e., new water or TMPP's allotment of BMP Water). There will be no Reclaimed Water stored in this or any other tank. When ambient temperatures are high and more water is required in the cooling tower basin than is available from the WWTP, then additional water will be pumped to the cooling tower basin from the 500,000 gallon fresh water storage tank.

WASTE WATER TREATMENT

Process wastewater will be processed and reused. Most cooling water will be consumed in the cooling towers and evaporated. Chemicals and solid material contained in the cooling water will be concentrated as water is evaporated. A portion of the circulating cooling water is removed from the system to limit the concentration of chemicals in the water (e.g., blowdown). The applicant is proposing a waste water crystallizer to concentrate the blowdown. This system will produce a solid waste which will be disposed of in an appropriate land fill. See the Waste Management section.

NATURAL GAS PIPELINE

Natural gas will be supplied to the project via a new 2,500 to 7,000 foot 12-inch pipeline connection with Pacific Gas and Electric Company's (PG&E) natural gas pipeline located southeast of the project site. The applicant has identified three alternative routes for the natural gas pipeline connection. The applicant's September 2, 1999 response to staff's data request 16 indicated that route A will be used. This route calls for a 2,900 foot connection. The proposed gas line routes are show on **PROJECT DESCRIPTION** Figure 2.

PROJECT DESCRIPTION Figure 3
Project Layout

TRANSMISSION LINE FACILITIES

The project will connect to PG&E's 230 kilovolt (kV) network adjacent to the existing McCloud River Railway right-of-way utilizing a new PG&E 230 kV switchyard via two new double circuit 230 kV lines and a new 230 kV single circuit transmission line from the TMPP switchyard to the PG&E switchyard (TMP 1999a, AFC pages 2-1, 2-65, Figure 3). See **PROJECT DESCRIPTION** Figure 3 for location of switchyard and new transmission line. **PROJECT DESCRIPTION** Figure 4 shows the typical double circuit 230 kv steel poles proposed.

A new PG&E switchyard will be located on the project site. The line connecting the TMPP facility to PG&E's switchyard will be a 230 kV single circuit transmission line. The tie-in with the existing PG&E 230 kV Pit River hydro transmission line is approximately 800 feet west and then 1800 feet in a northerly direction adjacent to the McCloud River Railroad easement. The Pit #1-Pit #3 230 kV transmission circuit and the Pit #1-Cottonwood 230 kV transmission circuit will be intersected and looped to the new PG&E switchyard. To accommodate the TMPP power output, 60 lineal miles of reconductoring[1] utilizing existing towers to the Round Mountain and Cottonwood substations is proposed. These transmission lines are shown on **PROJECT DESCRIPTION** Figure 1.

CONSTRUCTION

The project is estimated to have a capital cost of about $250 million. The applicant plans to complete construction and start operation of the TMPP by the third quarter of 2002. During construction, an average of approximately 200 workers would be employed. During operation, the TMPP would employ 20 to 25 full-time staff. Construction is expected to require 18 months. See the **Socioeconomic** section of this staff assessment for additional details on project construction of schedule and the work force necessary to support this project. See the **Waste Management** section of this staff assessment for discussion of disposal of wastes generated during construction. The overall sequence of construction and start-up includes: site preparation, construction foundations, erecting major structures, installing major equipment, connecting major site interfaces (pipelines and transmission line), start-up testing, and final siting cleanup and landscaping.

[1] "Reconductoring" consists of removing the old insulators, installing new insulators and replacing the old conductors with new conductors with a higher capacity.

PROJECT DESCRIPTION Figure 4
Typical Double Circuit 230 kV Steel Pole

AIR QUALITY

Testimony of Tuan Ngo, P.E.

INTRODUCTION

This analysis addresses the potential air quality impacts resulting from criteria air pollutant emissions created by the construction and operation of the Three Mountain Power Project (TMPP). Criteria air pollutants are those for which a state or federal standard has been established. They include nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), ozone (O3) and its precursors (NOx and VOC), volatile organic compounds (VOC), particulate matter less than 10 microns in diameter (PM10) and its precursors: NOx, VOC, SOx, and lead (Pb).

In carrying out this analysis, the California Energy Commission staff evaluated the following major points:

- whether the TMPP is likely to conform with applicable Federal, State and Shasta County Air Quality Management District (District) air quality laws, ordinances, regulations and standards, as required by Title 20, California Code of Regulations, section 1742.5 (b);
- whether the TMPP is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards, as required by Title 20, California Code of Regulations, section 1742 (b); and
- whether the mitigation proposed for the TMPP is adequate to lessen the potential impacts to a level of insignificance, as required by Title 20, California Code of Regulations, section 1744 (b).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

A new, major facility, located in an area that is not in attainment with the National Ambient Air Quality Standards (NAAQS) (non-attainment area), is subject to the federal New Source Review (NSR) program. The proposed project is located in an area that is designated as attainment for ozone, CO and PM10. The area is unclassified for the federal NO2 and SO2 standards, and therefore, is not subject to the federal NSR requirements for these pollutants. However, the TMPP will be subject to federal Prevention of Significant Deterioration (PSD) review. In general, under the PSD program, the project must comply with Best Available Control Technology (BACT) for PM10, NO2, SO2 and CO and demonstrate that its emission impacts will not significantly degrade the existing ambient air quality in the region. The Environmental Protection Agency (EPA) has delegated the authority to administer the PSD program to the District.

The TMPP's gas turbines are also subject to the federal New Source Performance Standards (NSPS). These standards include a NOx emissions concentration of no more than 75 parts per million (ppm) at 15 percent excess oxygen (ppm@15%O2), and a SOx emissions concentration of no more than 150 ppm@15%O2.

STATE

California State Health and Safety Code, Section 41700, requires that: “no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerate number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property.”

LOCAL

As part of the Commission’s licensing process, in lieu of issuing a construction permit to the applicant for the TMPP, the District has prepared and presented to the Commission a Determination of Compliance (DOC). The DOC evaluates whether and under what conditions the proposed project will comply with the District’s applicable rules and regulations, as described below. The Commission staff coordinated its air quality analysis with the District staff as it prepared the DOC, and has incorporated the Final DOC recommended conditions of certification in this Final Staff Assessment.

The project is subject to the specific District rules and regulations that are briefly described below:

Rule 2.1: New Source Review (NSR): This local rule requires that the project be equipped with Best Available Control Technology (BACT) for each individual piece of equipment if its emissions exceed 25 pounds a day of reactive organic compounds (VOC) or nitrogen oxides (NOx), or exceed 80 pounds a day of particulate matter less than 10 microns in diameter (PM10) or sulfur oxides (SOx), or exceed 500 pounds a day of carbon monoxide (CO). In addition, the rule prohibits the approval of a project if the project, including offsets, causes a new violation or makes worse an existing violation of the ambient air quality standards.

Rule 2.2: Emission Reduction Credits and Banking: Provides administrative procedures for quantification, registration and use of emission reduction credits generated from permanent reductions of permitted emissions sources. The requirements include the specific timing of an application for the credits and criteria for approval, such as the emission reduction credits must be real, enforceable, permanent, quantifiable and surplus.

Section (D)(4) states that under no circumstance shall any emission reductions occurring before July 26, 1994, other than those emission reductions described in Section (D)(5), be eligible for emission reduction credit certificates.

Section (D)(5) defines that emission reductions occurring after December 31, 1987 and before July 26, 1994, can be eligible for emission reduction credits if such reductions are actual and have been formally recognized by the District in writing and the emissions were included in the District’s emission inventory.

Section J specifies that the method used to calculate the emission reduction credits must be consistent with the method described in the District's NSR rule, which means that the credits shall be equal to the difference between the historical actual emissions and the proposed emissions.

Rule 2.28: Prevention of Significant Deterioration: This rule incorporates all elements and requirements of the Federal Prevention of Significant Deterioration program, including BACT and a modeling demonstration that the project will not significantly degrade the existing ambient air quality in the region.

Rule 3.28: Internal Combustion Engines: This rule establishes a NOx emission limit of 150 ppm and a CO emission limit of 4500 ppm for gas turbines.

Shasta County General Plan Policy AQ-2(e): This Shasta County General Air Quality policy specifies that any new project with emissions of non-attainment pollutants or their precursors exceeding 25 tons per year shall provide appropriate emission offsets.

ENVIRONMENTAL SETTING

METEOROLOGICAL CONDITIONS

The project is located approximately one mile north of the town of Burney, at an elevation of 3,140 feet above sea level. At this level, the site is above the level of the inversion layer that affects the air quality in the northern Sacramento Valley (TMPP, 1999). During the winter months, the site may experience some inversions that trap the pollutants generated within the Burney Valley. The area is characterized by mild winters and cool summers, with an average of 28 inches of precipitation per year.

The most recent (1997 and 1998) surface meteorological data, which are representative of the area, were collected at the Soldier Mountain monitoring station. The station is actually located at mid summit of Brush Mountain, approximately 4 miles northeast of Burney. The measured wind data are graphically presented as quarterly and annual wind roses in Appendix A. These wind roses show that the prevailing winds at the site during the summer months are from the south to southwest, and during the winter months are from the north. The wind roses indicate that the area experiences a large percentage of calms in winter, 46 percent, compared to 12 percent of calms in spring, 6 percent of calms in summer, and 30 percent of calms in fall.

EXISTING AMBIENT AIR QUALITY

The federal and state ambient air quality standards (AAQS) represent the allowable maximum ambient concentrations of air pollutants, and are established by both the U.S. Environmental Protection Agency (EPA) and the California State Air Resources Board (CARB). The state AAQS, established by CARB, are typically lower (more stringent) than those established by EPA. The state and federal air quality standards are listed in **AIR QUALITY Table 1**. The averaging times for the various air quality standards (the times over which they are measured) range from one hour to one year. The standards are expressed either as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant in a cubic meter of air (mg/m^3 and $\mu g/m^3$).

In general, an area is designated as attainment if the concentrations of a particular air contaminant do not exceed an ambient air quality standard. Likewise, an area is designated as non-attainment for an air contaminant if that standard is violated. Where not enough ambient data are available to support designation as either attainment or non-attainment, the area can be designated as unclassified. Unclassified areas are normally treated the same as attainment areas for regulatory purposes. An area can be attainment for one air contaminant while non-attainment for another, or attainment for the federal standard and non-attainment for the state standard for the same contaminant. The entire area within the boundaries of a district is usually evaluated to determine the district's attainment status.

The District is located in the Sacramento Valley Air Basin and has the same boundaries as Shasta County. It is currently classified as attainment for the federal ozone, CO and PM10 standards, and unclassified for the federal NO2 and SO2 standards. The District is currently designated as attainment for the state NO2 and SO2 standards, unclassified for the state CO standard, and non-attainment for the state ozone and PM10 standards.

EXISTING CO, NO2 AND SO2 AMBIENT AIR QUALITY FOR THE AREA

Ambient air quality data for ozone, PM10 and CO were collected at the project site between the period of 1989 through 1993. The monitoring station operated for a five-year period. The data are presented in **AIR QUALITY Table 2**. After 1993, the station was dismantled and no ambient data have been collected at the site since then.

For CO, the ambient concentrations recorded were around 2300 $\mu g/m^3$, which is well below either the state or the federal CO air quality standards.

Staff has not been able to obtain any recent ambient NO2 or SO2 data for the area. The only available ambient data available are three years of 1-hour NO2 data (from 1990 to 1992) collected at the Redding monitoring station, which is located in the most populous area of the county where mobile and industrial sources contribute significantly to NO2 levels. The data indicate that the highest recorded 1-hour NO2 concentrations were between 132 and 94 $\mu g/m^3$, which were well below the state standard of 470 $\mu g/m^3$. As mentioned earlier, because of the lack of major industrial sources and no significant increase of population in the Burney area, staff believes that the NO2 concentration in Burney would be well below those measured at the Redding monitoring station. Therefore, the use of Redding ambient NO2 data should be overly conservative.

AIR QUALITY Table 1
Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards	Federal Standards	
			Primary	Secondary
Ozone(O3)	1-hour	0.09 ppm (180 µg/m^3)	0.12 ppm (235 µg/m^3)	same as primary
Particulate Matter (PM10)	Ann.Geo. Mean	30 µg/m^3	---	same as primary
	24-hour	50 µg/m^3	150 µg/m^3	
	Ann.Arit. Mean	---	50 µg/m^3	
Carbon Monoxide (CO)	1-hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	None
	8-hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	
Nitrogen Dioxide (NO2)	1-hour	0.25 ppm (470 µg/m^3)	---	same as primary
	Ann.AritMean	---	0.053 ppm (100 µg/m^3)	
Lead(Pb)	30-day	1.5 µg/m^3	---	same as primary
	Cal. Quarter	---	1.5 µg/m^3	
Sulfur Dioxide (SO2)	Ann.Arit. Mean	---	0.03 ppm (80 µg/m^3)	---
	24-hour	0.04 ppm (105 µg/m^3)	0.147 ppm (365 µg/m^3)	---
	3-hour	---	---	0.5 ppm (1300 µg/m^3)
	1-hour	0.25 ppm (655 µg/m^3)	---	---
Sulfates	24-hour	25 µg/m^3	No federal standard	
H_2S	1-hour	0.03 ppm (42 µg/m^3)	No federal standard	

Source: California Air Resources Board

As for SO2, the whole county is classified as attainment for the state and unclassified for the federal SO2 standards. Even though local ambient SO2 concentration data are not available, staff believes that the area is comparable with the SO2 data for the Sacramento Valley air basin due to the lack of industrial and mobile sources compared to the Redding or Sacramento areas. The highest measured 24-hour SO2 concentration, measured at the Sacramento Del Paso Manor monitoring station, that is representative of the entire basin, is 0.018 ppm. This is well below the state and federal 24-hour SO2 ambient standards of 0.04 and 0.147 ppm, respectively.

The existing ambient air quality data for CO, NO2 and SO2 are tabulated in **AIR QUALITY Table 2**.

EXISTING OZONE AMBIENT AIR QUALITY FOR THE AREA

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between directly emitted air pollutants. Nitrogen oxides (NOx) and hydrocarbons (Volatile Organic Compounds [VOC]) interact in the presence of sunlight to form ozone.

Although the ambient air quality data in **AIR QUALITY Table 2** are sketchy and not up to date, staff believes that the data are suitable to describe the conditions of the area where the facility is going to be sited. Staff has reviewed the Burney area's inventory of stationary sources emissions from 1990 to 1996 (the latest data available), and finds that the Burney area lacks of sufficient industrial sources to produce significant NO2 and VOC (ozone precursors) emissions. The emission inventory data from 1990 to 1996 were tabulated in **AIR QUALITY Table 3**. These data indicate that the area has not experienced any growth in stationary sources' emissions since 1990. Based on this review, staff believes that the available data presented in **AIR QUALITY Table 2** represent the current environment of the Burney area.

AIR QUALITY Table 2
Maximum Ambient Air Quality Measurements Recorded at the Burney Monitoring Station (1989 through 1993)

Pollutant	Averaging Time	1993	1992	1991	1990	1989	Most Restrictive Ambient Air Quality Standard
Ozone (pphm)	1-hr	NA	9	7	8	8	9 (CAAQS)
No. of violations		NA	0	0	0	0	
PM_{10}($\mu g/m^3$)	24-hr	91	86	80	80	91	50 (CAAQS)
	Annual	35	29	29	29	29	30 (CAAQS)
Calculated no. of days of violation		18	36	60	54	54	
NO2[1] ($\mu g/m^3$)	1-hr	NA	94	132	132	NA	470 (CAAQS)
CO($\mu g/m^3$)	8-hr	NA	1150	2300	2620	2875	10000 (CAAQS & NAAQS)
SO2($\mu g/m^3$)	1-hr	NA	NA	NA	NA	NA	655 (CAAQS)

Notes: CAAQS = California Ambient Air Quality Standard
NAAQS = National Ambient Air Quality Standard
[1] Data for the 1-hour NO2 are from the Redding monitoring station.
NA = data are not available

Source: CARB: California Air Quality Data.

The ambient ozone concentrations recorded between 1989 and 1992 have ranged from 7 to 9 parts per hundred millions (pphm). The area did not experience any violations of either the state or federal ozone air quality standards.

AIR QUALITY Table 3
1990 through 1996 Burney Area Industrial Stationary Source Emission Inventory

POLLUTANTS	1990[1]	1993	1995	1996
VOC	74	37	40	57
CO	1975	1680	1280	1580
NO2	297	416	582	270
PM10	200	48	56	67

Source: ARB emission inventory.
[1] 1990 emission inventory is not completed.

EXISTING PM10 AMBIENT AIR QUALITY FOR THE AREA

PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SOx and VOC from turbines, given the right meteorological conditions, form particulate matter known as nitrates (NO3), sulfates (SO4), and organics. These pollutants are known as secondary particulates, because they are not directly emitted but are formed through complex chemical reactions in the atmosphere.

Unlike ozone, the Burney area experiences numerous violations of the state PM10 ambient air quality standards. During the period of measurements (1989 through 1993), the data shows that PM10 violations occurred between the months of November through March when the weather is cold. The Burney area experiences a low inversion layer during these cold months. This low inversion layer traps the pollutants causing a build up of pollutants, which contributes to the violations of the PM10 air quality standard.

WHAT CAUSES PM10 VIOLATIONS IN THE BURNEY AREA?

A review of the industrial emission inventory data in **AIR QUALITY Table 3** reveals that there are only five industrial stationary sources in Burney. They are Burney Forest Products, Burney Mountain Power, PG&E, Dicalite, and Sierra Pacific. These five sources' PM10 emissions have been reduced from 200 TPY in 1990 to 67 TPY in 1996. Some area residents believe that the operation of the Burney Mountain Power facility and the expansion of the Dicalite mining facility may worsen the PM10 air quality in the Burney area in future years. The emission inventory data indicates that the Burney Mountain Power facility's PM10 emissions were steadily reduced from the 140 TPY level in 1990 to 16.5 TPY in 1996. The Dicalite facility is a mining operation where fugitive dust may be a problem, but staff does not believe that the mining operation causes any significant dust problem in the winter because the soil is wet, and thus dust would not be entrained into the air.

Based on the above review, staff believes that the PM10 problem in this area is caused primarily by residential wood heating devices, which is a typical problem for mountain community areas. According to the District staff, in 1990, the District attempted to develop a measure to control the emissions from wood stoves and fireplaces in Shasta County. This control measure would have required that all new houses be equipped with clean burning wood stoves, and that older wood stoves would be upgraded with clean burning wood stoves when a house is sold. The District adopted the control measure, but the provision that requires upgrading of wood stoves when a house is sold was deleted.

In conclusion, staff believes that the area has not experienced any significant change in population, has experienced shown a reduction of emissions from industrial stationary sources, and that the ambient PM10 data collected from 1989 to 1993 are therefore representative of the area's existing conditions. However, in response to questions raised by the local community about the ambient conditions of the area, staff recommends, as a condition of certification, the applicant collect five years of ambient ozone and PM10 data to enhance the understanding of the area's air quality condition. The first two years of data collection will be prior to and during the construction of the project, with the remaining three years of data collection to occur after the project commences operation.

The available ambient PM10 data indicated that the area has experienced some improvement in ambient PM10 conditions from 1989 to 1993. The PM10 concentrations recorded were as high as 91 μg/m3 during this period. There were 50 to 60 calculated days of PM10 violations per year from 1989 through 1991. Those numbers were reduced to 18 to 36 days per year in 1992 and 1993. [The number of days of violations are calculated based upon the number of violations measured. PM10 levels are ordinarily recorded once every six days, therefore, the number of calculated days is calculated by multiply the number of measured violations by six.] Based on these data, the area has not experienced any significant improvement in terms of PM10 concentrations, although there has been a reduction of the frequency of PM10 violations.

PROJECT EMISSIONS

CONSTRUCTION ACTIVITIES

The construction of the proposed project will last approximately 20 months, and generally consists of two major activities; site preparation, and construction and installation of major equipment and structures. The applicant provided estimated peak hourly, daily and annual construction equipment exhaust emissions (TMPP 1999, Table 6.8-8). The maximum daily construction emissions are identified in **AIR QUALITY Table 4**. Staff reviewed the applicant's estimated construction emissions, and believes that they are reasonable.

Emissions from construction equipment exhausts, such as vehicles and internal combustion engines, are also expected during the project construction phase. A small amount of hydrocarbon emissions may also occur as a result of the temporary storage of petroleum fuel at the site.

Site preparation, which would last for approximately nine (9) months, involves clearing and grading of the 10.2 acres site, and completion of the facility's foundations. Construction equipment used at this phase includes a motor grader, four tractors, one excavator hydraulic crawler, one vibrator compactor, three cranes, and various heavy duty construction equipment and trucks, including concrete and water spray trucks. The applicant provided maximum fugitive dust PM10 emissions from site preparation (TMPP 1999, Tables 6.8-9). They are presented in **AIR QUALITY Table 4** for each activity, including excavation, compacting, grading, back-filling, fugitive emissions, and construction vehicles traveling on unpaved areas.

AIR QUALITY Table 4
Maximum Unmitigated Daily Construction Emissions (lbs/day)

Construction Emission Sources	NOx	SO2	VOC	CO	PM10
Facility Construction					
Heavy Equipment	368	34	46	335	22
Worker Vehicles	1	Neg.	1	9	Neg.
Fugitive Dust					215
Water Pipeline	8	1	Neg.	4	Neg.
Fugitive Dust					153
Natural Gas Pipeline	16	1	2	9	Neg.
Fugitive Dust					253
Transmission Line Tie-in	21	2	2	36	1
Fugitive Dust					92
Total	**410**	**40**	**50**	**390**	**740**

Sources: AFC Tables 6.8-7 through 6.8-9.

In addition to construction of the main facility, there will be a new water line (approximately 5,280 feet) and a new natural gas pipeline (approximately 8,986 feet long). The applicant provided maximum emissions for these construction activities (TMPP, 1999), which are also included in **AIR QUALITY Table 4**.

For the water and natural gas pipelines, construction activities will consist of excavation/trenching, pipe laying, and back filling and compaction. Equipment used in the construction of the water and natural gas pipelines include two backhoes, two trenchers, two compactors, one welding machine and various trucks for supplies and water. It is assumed that the construction activities of these two linear facilities will be continuous for 8 hrs/day, five days per week for the entire construction period of these two facilities. The applicant provided maximum daily construction emissions for all construction activities (TMPP, 1999), which are included in **Air Quality Table 4**.

PROJECT OPERATION

The project will be built with the following major components:

Two natural gas fired combustion turbines (either GE Frame 7 or Westinghouse 501F),

- Two heat recovery steam generators (HRSG),
- One steam turbine,
- One hybrid wet and dry cooling tower, and
- One emergency diesel fuel water pump to be used in case of fire.

The turbines will be operating in combined cycle mode to produce approximately 500 MW of electricity. The facility is expected to be at least 95 percent available and can operate up to 8,322 hours per year. Each HRSG will be equipped with a duct burner to increase steam production. The applicant proposes to equip each combustion turbine with a dry low NOx combustion technology and a selective catalytic reduction (SCR) system in the HSRG, which together limits the NOx emissions to 2.5 ppm@15% O2. TMPP will also committed to a three year demonstration that the project NOx emissions to be maintain at 2 ppm based on a one-hour average. After three years if the NOx emissions can be maintained at that level, TMPP will accept 2 ppm as the limit for the power plant (TMPP 2000 c). To control the CO and VOC emissions, the applicant proposes to equip each combustion turbine/HRSG with a high-temperature oxidation catalyst system, which limits the CO emissions to 4 ppm and the VOC emissions to 2 ppm (TMPP 2000 c).

The applicant is requesting that the project be analyzed with the assumption of one cold-start, 50 warm-starts, 255 hot-starts and 306 shutdowns per turbine each year. A hot start would occur after an overnight turbine shutdown. The duration of a hot start is relatively short, approximately half an hour. A warm start-up duration would occur after a typical weekend shutdown (approximately 60 to 72 hours). A warm start-up is also approximately 30 minutes in duration, although the steam turbine ramping up period would be longer than a hot start. A cold start takes considerably longer, as much as three hours. However, this type of start-up would be very rare, occurring only after the turbines have been under extended shutdown, such as the annual maintenance inspection that the manufacturer may require.

The facility's hourly, daily and annual emissions were estimated with information on the Westinghouse 501F and GE7F turbines provided by the applicant, and are presented in **AIR QUALITY Tables 5, 6 and 7**.

The hybrid cooling tower is equipped with drift eliminators that limit the drift rate to 0.0005 percent. The cooling tower is designed to circulate approximately 125,000 gallons of water per minute (gpm). The cooling tower emissions are estimated using this circulation rate, a drift rate of 0.0005 percent and a 5000 ppm total dissolved solid content of the cooling tower make up water.

The daily emissions from the project are shown in **AIR QUALITY Table 6**. The table shows different operating scenarios, and the resultant emissions, including CTG startup (cold, warm and hot), shutdown, and steady state operation. Staff has not included the emissions of the emergency diesel fueled fire pump because it is used only in case of emergency during which time the turbines are not operating. In addition, the emergency generator would add approximately three pounds of NOx emissions each week during its 30 minutes testing. This amount of emissions is relatively insignificant and will not change the impact of the project. The project's typical daily emissions are presented in the last row of the table.

AIR QUALITY Table 5
Project Hourly Emissions
(pounds per hour [lb/hr] except where noted)

Operational Profile	NOx	SO2	PM10	VOC	CO
GE7FA Cold Start-up (4 hours)	430	8	240	160	1500
GE7FA Warm Start-up (120 min.)	275	4	140	60	900
GE7FA Hot Start-up (90 min.)	150	3	100	60	850
GE7FA Shutdown (30 min.)	75	1	30	50	350
GE7FA Steady State @ 100% load	34.6	2	40	9.6	50.6
W501F Cold Start-up (3 hours)	280	8	240	278	2210
W501F Warm Start-up (120 min.)	246	4	140	277	2230
W501F Hot Start-up (60 min.)	223	3	100	229	1700
W501F Shutdown (30 min.)	75	1	30	51	350
W501F Steady State @ 100% load	31.2	2	32.7	8.7	45.5
Cooling Towers	--	--	1.60	--	--
Total Facility Emissions at Steady State (lbs/hr)	34.6	4	42	9.6	50.6

Source: TMPP, 1999a.

AIR QUALITY Table 6
Project Daily Emissions
(pounds per day [lb/day])

Operational Profile	NOx	SO2	PM10	VOC	CO
2 turbine sequential cold-start and steady state operation (GE7A)	1,120	48	1,040	350	2,510
2 turbine sequential cold-start and steady state operation (W501F)	940	48	930	460	3,170
2 turbine 24-hr steady state full load operation (GE7A)	830	48	960	230	1,210
2 turbine 24-hr steady state full load operation (W501F)	750	48	780	210	1,100
Cooling towers operating 24-hr	--	--	40	--	--
Maximum steady state daily operation: 2 turbines and cooling towers	830	48	1,000	230	1,210

Source: TMPP, 1999a.

AIR QUALITY Table 7
Project Annual Emissions
(tons per year [TPY])

Operational Profile	NOx	SO2	PM10[1]	VOC	CO
1 cold start, 50 warm starts, 255 hot starts, 4,912 hr steady state[2] (GE7FA)	123	9	125	40.7	310
Steady State for 8,322 hrs per year (GE7FA)	144	9	173	40.1	210
1 cold start, 50 warm starts, 255 hot starts, 4,912 hr steady state[3] (W501F)	123	9	101	65.4	438
Steady State for 8,322 hrs per year (W501F)	130	9	136	36.2	189

Notes:
1 Including cooling tower emissions.
2 Assume 4 hr for each cold start, 2 hr for each warm start, 1.5 hr for each hot start, 4,912 hr steady state, and 8322 hours cooling towers operation.
3 Assume 3 hr for each cold start, 2 hr for each warm start, 1 hr for each hot start, 4,912 hr steady state, and 8322 hours cooling towers operation.
Source: TMPP, 1999a.

INITIAL COMMISSIONING

The initial commissioning refers to a period of approximately 60 days prior to beginning commercial operation when the combustion turbines will undergo initial test firing. During this commissioning phase, the project may operate at a low-load for a long period of time for fine-tuning. The District has required that each activity of the commissioning period be planned carefully, and that all NOx and CO emissions and the time of commissioning be optimized to lessen the excess emissions from the turbines, duct burners and HRSG. It should also be noted that the NOx and CO emissions during the commissioning period are not higher than those happen during normal start up of the facility; therefore, no new additional impacts will be a direct result of the emissions during the commissioning period. In addition, all criteria air contaminant emissions during the commissioning period will be counted toward the annual emission limits. Thus there is an incentive for the applicant to limit the commissioning period to the shortest time possible.

CLOSURE

Eventually the TMPP will close, either as a result of the end of its useful life, or through some unexpected situation, such as a natural disaster or catastrophic facility breakdown. When the facility closes, then all sources of air emissions will cease and thus all impacts associated with those emissions will no longer occur. The only other expected emissions will be fugitive particulate emissions from the dismantling activities. These activities will be short term and will create fugitive dust emissions levels much lower than those created during the construction of the project. Nevertheless, staff recommends that a facility closure plan to be submitted to the Energy Commission Compliance Project Manager to demonstrate compliance with applicable District Rules and Regulations during closure activities.

AMMONIA EMISSIONS

Due to the large combustion turbines used in this project and the need to control NOx emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia will mix in the flue gases to reduce NOx; a portion of the ammonia will pass through the SCR and is emitted unaltered, out the stacks. These ammonia emissions are known as ammonia slip. The applicant has committed to an ammonia slip no greater than 5 ppm, which is the current lowest ammonia slip level being permitted throughout California (TMPP 2000 c).

On a daily basis, a 5 ppm slip is equivalent to approximately 1,200 pounds of ammonia emitted into the atmosphere. However, based on the ammonia slip levels of existing power plants in California, staff believes that the expected ammonia emissions from the project would be no more than 150 lbs/day (less than 1 ppm). Also, staff does not believe that the permitted ammonia slip will contribute significantly to additional secondary PM10 formation in the area due to the absence of the nitric acid and free hydroxide radicals typically found in more industrialized areas.

IMPACTS

Air dispersion models provide a means of predicting the location and magnitude of the air contaminant impacts of a new emissions source at ground level. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions. The model results are often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$). They are an estimate of the concentration of the pollutant emitted by the project that will occur at ground level.

The applicant has used an EPA-approved ISCST3 model to estimate the impacts of the project's NOx, PM10, CO and SOx emissions resulting from project construction and operation. A description of the modeling analyses and results are provided in Appendix E of the AFC (TMPP, 1999) and the December 15, 1999 submittal (TMPP, 1999b). Staff added the applicant's modeled impacts to the available highest ambient background concentrations measured during 1989 through 1993 at the Burney monitoring station. Staff then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or contribute to an existing violation.

Inputs for the modeling include stack information (exhaust flow rate, temperature, stack dimensions), specific turbine emission data and meteorological data, such as wind speed, atmospheric conditions, and the site elevation. For this project, the meteorological data used as input for the modeling included the hourly wind speeds and directions measured at the Soldier Mountain monitoring station. It should be noted that the monitoring station name is Soldier Mountain, but it is not physically located at Soldier Mountain. The true physical location of the monitoring station is at mid-summit of Brush Mountain, which is located about four miles west of the project site and at an elevation of approximately 3,500 feet (the project is located at an elevation of 3,173 feet).

The local residents expressed concerns that the meteorological data used in the model are not representative of the local conditions. Therefore, staff requested that the applicant perform an additional modeling analysis that incorporated all stack information, the specific turbine emission data, and a set of artificial severe meteorological data. This type of modeling analysis will result in the worst possible potential impacts that the project could cause, but which are not expected to occur. The results of this analysis are used to verify that the project will not cause a violation, will not contribute significantly to the existing PM10 violation of the area, and will not exceed any PSD increment increase in the ambient air.

CONSTRUCTION IMPACTS

The results of the project construction impacts are presented in **AIR QUALITY Table 8**. The modeling analyses included both the fugitive dust and vehicle exhaust emissions, which include PM10, NO2 and CO. In **AIR QUALITY Table 8**, the first column represents the air contaminant, i.e., NO2, PM10, and CO. The second column presents the averaging time for each air contaminant analyzed. The third column presents the project emission impacts. The fourth column presents the highest measured concentration of the criteria air contaminants in the ambient air (background). The fifth column presents the total impact, i.e., the sum of project emission impact and background measured concentration. As indicated in **Air Quality Table 8**, the project construction activities further exacerbate existing violations of the state 24-hour PM10 standard. In reviewing the modeling output files, the project's construction impacts are not expected to be occasional or isolated events, but will occur over an area at the project's property fence lines where the general public does not have access.

The predicted impacts are high for a number of reasons. First, the model itself calculates impacts that are very conservative, usually exceeding actual impact levels by a considerable margin. Second, the analysis assumes that all the NOx emitted from the vehicles is in the form of NO2. In reality, approximately 90 percent of NOx emissions from a combustion source are in the form of nitrogen oxide (NO), which eventually would oxidize to NO2 as they disperse in the atmosphere. Therefore, the one-hour NO2 impact shown in the modeling analysis does not realistically reflect the possible one-hour NO2 impact.

Third, some of the sources of combustion emissions (the bulldozers and trucks) are mobile sources, not stationary sources. Therefore, as mobile sources, the air quality impacts would not always be at the same locations, so the modeling results are overstated. Fourth, it was assumed that all the equipment identified for the modeling evaluation would be running simultaneously. It is doubtful that all the major equipment, 4 large bulldozers, 4 backhoes, 12 cranes and 5 large flatbed trucks, would all be operating at one time, and thus the impacts are overstated.

Finally, the emissions inputs to the model were from the highest monthly emissions assumed during the 20-month construction period. The levels of emissions used reflect a period of activity of approximately one year, not the entire construction period. During the other months of construction work, considerably less emission generating equipment will be used and thus the impacts will be even lower.

AIR QUALITY Table 8
Facility Construction Impacts

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impacts ($\mu g/m^3$)	Standards ($\mu g/m^3$)	Percent of Standard
NO2[1]	1-hr.	330	130	460	470	99%
CO	8-hr.	1,870	2870	4,740	10,000	47%
PM10	24-hr.	201	91	292	50	584%

Notes: 1. NO2 emission impacts was estimated using ozone limiting method.

Construction of the TMPP will result in unavoidable short-term PM10 impacts. Because the area is non-attainment for PM10, additional impacts during construction of the project can be viewed as significant. However, it is doubtful that the general public would be exposed to the construction impacts associated with the project. This is because the highest PM10 impacts are registered at the property fence line and drop off to about 26 μg/m3 at the nearest residential area of Johnson Park. Nevertheless, staff believes that the impacts from the construction of the project can be further reduced with the implementation of the staff recommended construction mitigation measures, as discussed in the Mitigation section.

OPERATION IMPACTS

The applicant provided staff with a modeling analysis of the project's operating emissions impacts from directly emitted pollutants, which they believe demonstrates that no violations of ambient air quality standards will be caused by the operation of the project. Staff reviewed the applicant's modeling analysis and concludes that it is adequate.

AIR QUALITY Table 9 presents the results of the modeling analysis using worst case hourly emissions, which include turbine start-up and cooling tower emissions as presented in **AIR QUALITY Table 5**. **AIR QUALITY Table 9** shows that, with the exception of PM10, the project does not cause any new violations of any applicable air quality standard. As for PM10, staff does not believe that the project itself causes a violation of either the 24-hour or the annual PM10 air quality standards. However, the project's impacts will contribute to the PM10 violations in the area that regularly occur during the cold months of the year when wood stoves and fireplaces are commonly being used. Therefore, the project's PM10 emission impacts are significant. To mitigate these impacts, staff recommends that the project PM10 emissions be offset by emission reductions from the local area. The staff suggested mitigation measures are discussed in detail in the Mitigation section of this analysis.

AIR QUALITY Table 9
Worst Case Facility Emission Impacts on Ambient Air Quality

Pollutants	Avg. Period	Impacts(μg/m^3)	Background (μg/m^3)	Total Impacts (μg/m^3)	Standard (μg/m^3)	Percent of Standard
NO2	1-hour	224	134[1]	358	470	76%
	Annual	1	22	23	100	23%
SO2	1-hour	2	n/a	n/a	655	n/a
	24-hour	1	n/a	n/a	n/a	n/a
CO	1-hour	1,000	4,570	5,570	23,000	24%
	8-hour	465	2,860	3,325	10,000	33%
PM10	24-hour	11	91	102	50	204%
	Annual	2	35	37	30	123%

Note: [1] The background concentration of NO2 is from the Redding Monitoring station.

CUMULATIVE IMPACTS

Staff's cumulative impact assessment is composed of two types of analysis. The first is an analysis of the project's directly emitted pollutants along with similar emissions from other foreseeable future projects that are currently under construction, or are currently under District review. The second is a discussion of the project's potential contribution to the formation of secondary pollutants, namely ozone and PM10.

DIRECTLY EMITTED POLLUTANT IMPACTS

To evaluate the direct emission impacts of the TMPP along with other probable future projects, staff needs specific information about projects located up to six miles from the proposed facility. Staff assumes that impacts from projects beyond six miles would not effect the modeling analysis on a cumulative basis. Staff reviewed the District permit files and found that there are no major sources currently being built or proposed to be built within the six miles radius of the project site. Therefore, a directly emitted pollutant cumulative impact analysis was not performed.

SECONDARY POLLUTANT IMPACTS

OZONE IMPACTS

The project's gaseous emissions, primarily NOx and VOC can contribute to the formation of ozone. There are air dispersion models that can be used to quantify ozone impacts, but they are only appropriate for use in regional air quality planning efforts where numerous sources are input into the modeling to determine the regional ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, staff believes that the emissions of NOx and VOC from the TMPP do have the potential to contribute to higher ozone levels in the Sacramento Valley region if not mitigated. (The Sacramento Valley region is defined as the area stretching from Sacramento in the south to Redding to the north). TMPP NOx and VOC contribution to the regional ozone problem is not considered to be significant, because the applicant has proposed to purchase emission reduction credits of NOx and VOC to fully offset the emission increases caused by the proposed TMPP facility. As for the ozone contribution to the Burney area, staff believes that the TMPP NOx emissions will scavenge ozone in the vicinity of the project, thus reducing ambient ozone concentrations in the Burney area. Such scavenging is an air quality benefit, although it generally affects a smaller area than project's contribution to increased ozone concentrations in the region. Therefore, the project contribution to ozone concentration in the Burney area is not significant.

SECONDARY PM10 IMPACTS

The project's NOx, VOC, NH3 and SOx emissions can contribute to the formation of secondary PM10, namely nitrates, sulfates and organic condensable particulate matter.

Not all hydrocarbons (VOC) will form secondary PM10. Hydrocarbons with six or less carbon atoms in the chain will not participate in the formation of carbon-based PM10. The TMPP VOC emissions will be in the form of unburned natural gas, which is mostly methane and ethane, which contains only one to two carbon atoms. These compounds contain more than six carbon atoms in the hydrogen chain. Thus the turbine exhaust is not expected to emit any significant amount of VOC that will participate in the formation of secondary PM10.

Concerning ammonium nitrate, as described earlier, staff does not believe that the project will have any significant potential to contribute to the ammonium nitrate emissions to the area due to the lack of free hydroxide radicals and nitric acid in the area ambient air. Available research (Spicer, 1982) indicates that the conversion rate of NOx to nitrate is approximately between 10 to 30 percent per hour in a polluted urban area where ozone and ammonia are present in sufficient amount to participate in the reaction. Staff believes that the NOx to nitrate conversion rate is not even close to 10 percent in the Burney area because of the lack of ozone and NH3. Using a 10 percent NOx to nitrate conversion rate and a linear extrapolation of the project's PM10 modeling results, staff has estimated that the NOx to nitrate impact from the project can be at a maximum 0.5 $\mu g/m^3$, i.e., approximately equivalent to about 14 tons per year of direct PM10. This additional secondary PM10 together with the project's direct PM10 emissions will significantly contribute to the PM10 problem in Burney. Again, staff recommends that these impacts be mitigated by local emission reductions in the area. The staff recommendations are presented in more detail in the Mitigation Section.

Concerning sulfates as PM10, staff believes that the project will contribute to sulfates levels in the area, although in a very small amount. Currently, there is no agency (EPA or CARB) recommended models or procedures for estimating sulfate formation. Nevertheless, studies during the past two decades have provided data on the oxidation rates of SO2. The data from these studies can be used to approximate the conversion of SO2 to particulate (typically about 0.01 to 1 percent per hour) with Gaussian dispersion models such as ISCST3. The model can be performed with and without chemical conversion (decay factor) and the difference corresponds to the amount of SO2 that is converted to PM10. Because the project uses natural gas as fuel, very little SO2 emissions will be emitted; thus the SO2 to sulfates conversion modeling is not performed or needed. Staff still recommends that offsets, in the form of emission reductions in the local area, should be provided to lessen the project's PM10 contribution to the ambient air to the level of insignificance.

VISIBILITY IMPACTS

The applicant has provided as part of their PSD application to the District, a visibility impact analysis, which shows that the project is not expected to exceed any significant visibility impairment increment inside any nearby PSD Class I areas (TMPP,1999). Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective. There are three Class I areas within 100 km of the project site. They are Lassen Volcanic National Park (40 km), Thousand Lakes Wilderness (20 km) and Caribou Wilderness (45km) areas.

MITIGATION

APPLICANT'S PROPOSED MITIGATION

CONSTRUCTION PHASE

The applicant has provided a list of best available control measures to be employed during construction. These measures include the use of water or chemical stabilizers to disturbed areas, which are intended to lessen the short-term PM10 impacts on the ambient air. In addition, the applicant will limit fugitive emissions to a maximum 20 percent opacity during any three minute span, as required by District rules. Because the construction emissions are short-term, the applicant has not proposed any emission reduction credit to offset the new emissions.

OPERATION PHASE

The applicant proposes to mitigate the emission increases from the proposed facility using a combination of clean fuel, emission control devices and emission reduction credits. The applicant proposes to use a combination of dry low-NOx combustion design, Selective Catalytic Reduction (SCR) and high-temperature CO oxidation catalyst technology for each of the combined cycle turbine trains to minimize its NOx and CO emissions. The proposed control devices are designed to maintain the turbine/duct burner emissions to 2.5 ppm NOx, 4 ppm CO, and 2 ppm VOC (TMPP, 2000.c). It should be noted that the applicant has proposed to operate the facility with a NOx emissions level at 2 ppm for a three year demonstration period. After three years, if the facility can be operated consistently with the lower NOx limit, TMPP will accept a permit condition of 2 ppm NOx permanently. The ammonia slip emissions (from unreacted ammonia in the SCR) will be maintained at 5 ppm or less. Natural gas will be the only fuel used, which will minimize the project's PM10 and SOx emissions. In addition, the applicant will install a hybrid (wet and dry) cooling towers and equip the cooling towers with high efficiency drift eliminators that limit the drift rate to 0.0005 percent. The drift eliminators will minimize the cooling towers' PM10 emissions. Below is a brief description of the emission control technologies that TMPP will employ.

DRY LOW-NOX COMBUSTORS

Over the last 20 years, combustion turbine manufacturers have focused their attention on limiting the NOx formed during combustion. Because of the expense and efficiency losses due to the use of steam or water injection in the combustor cans to reduce combustion temperatures and the formation of NOx, CTG manufacturers are presently choosing to limit NOx formation through the use of dry low-NOx technologies. In this process, firing temperatures remain somewhat low, thus minimizing NOx formation, while thermal efficiencies remain high.

FLUE GAS CONTROLS

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, flue gas controls, primarily catalyst systems, will be installed in the HRSG. The applicant is proposing two catalyst systems, a selective catalytic reduction system (SCR) to reduce NOx, and an oxidizing system to reduce CO and VOC.

SELECTIVE CATALYTIC REDUCTION (SCR)

Selective catalytic reduction refers to a process that chemically reduces NOx by injecting ammonia into the flue gas stream over a catalyst in the presence of oxygen. The process is termed selective because the ammonia reducing agent preferentially reacts with NOx rather than oxygen, producing inert nitrogen and water vapor. The performance and effectiveness of SCR systems are related to operating temperatures, which may vary with catalyst designs. Flue gas temperatures from a combustion turbine typically range from 950 to 1100^{o}F.

Catalysts generally operate between 600 to 750^{o}F (ARB 1992), and are normally placed inside the HRSG where the flue gas temperature has cooled. At temperatures lower than 600^{o}F, the ammonia reaction rate may start to decline, resulting in increasing ammonia emissions, called ammonia slip. At temperatures above about 800^{o}F, depending on the type of material used in the catalyst, damage to some catalysts can occur. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or a noble metal are also used. These newer catalysts (versus the older alumina-based catalysts) are resistant to fuel sulfur fouling at temperatures below 770^{o}F (EPRI 1990).

Regardless of the type of catalyst used, efficient conversion of NO_x to nitrogen and water vapor requires uniform mixing of ammonia into the exhaust gas stream. Also, the catalyst surface has to be large enough to ensure sufficient time for the reaction to take place.

The applicant proposes to use a combination of dry low-NO_x combustor and an SCR system to produce a maximum NO_x concentration exiting the HRSG stack of 2 ppm, corrected to 15 percent excess oxygen averaged over a 1-hour period.

OXIDIZING CATALYST

To reduce the turbine CO and VOC emissions, the applicant proposes to install an oxidizing catalyst, which is similar in concept to catalytic converters used in automobiles. The catalyst is usually coated with a noble metal, such as platinum, which will oxidize unburned hydrocarbons and CO to water vapor and carbon dioxide (CO2). The CO catalyst is proposed to limit the CO concentrations to 4 ppm at 15 percent O2.

HYBRID COOLING TOWER

Hybrid cooling tower uses a combination of circulation cool air and water to condense the steam exiting the steam turbine and to maintain the lowest possible condenser vacuum, and thus, improve the power plant energy efficiency. During the cooling process, drift consists of small water droplets, which contain particulate matter that originates from the total dissolved solids in the circulating water. To limit the particulate emissions, drift eliminators are installed in the cooling tower to capture the water droplets. The applicant intends to use drift eliminators on the cooling tower with a design efficiency of 0.0005 percent. This is a very high level of efficiency for cooling tower drift eliminators.

OFFSETS

The Shasta County Air Quality Management District's New Source Review Rule 2.1 does not require the applicant to provide any emission offsets for the project. However, under the Shasta County General Plan Air Quality Policy 2.e, any new project that has emissions exceeding 25 tons per year (TPY) of any non-attainment air contaminants or their precursors shall provide emission offsets. Since the entire district is classified as non-attainment for the state 1-hour ozone and the 24-hour PM10 standards, and the project will exceed the 25 TPY threshold for NO2, VOC and PM10, the applicant has agreed to provide offsets for the project (TMPP, 1999).

The applicant has entered into an option agreement to purchase up to 153 TPY of NOx and up to 65 TPY of VOC emission reduction credits from Sierra Pacific. Sierra Pacific has been granted a banking certificate from the District for the 1984 shut down of equipment at the Anderson saw mill facility, which is located approximately 40 miles south west of Burney. According to the District, the emission reduction credits are sufficient in quantity to fully mitigate the project's NO2 and VOC emissions.

The applicant has identified four county owned candidate roads (Goose Valley, Jackrabbit Flat, Tamarack, and Mountain View roads) and six privately owned roads (Cottonwood, Fairfield, Vallejo, Bailey, Apple Orchard, and Goose Creek) near the town of Burney, that can be paved to offset the TMPP's 179 TPY of PM10 and sulfur dioxide (a precursor to PM10) emission increases. According to the preliminary vehicle count survey done by the applicant, the potential PM10 emission reduction credits for paving these roads are approximately 570 TPY (TMPP, 2000b). Thus there appears that the available emission reduction credits are sufficient to mitigate the project PM10 and SOx emissions, to which the District has combined as PM10 offset liability, as are required by the District General Policy 2e. It should be noted that not all of these roads are to be paved.

ADEQUACY OF PROPOSED MITIGATION MEASURES

CONSTRUCTION PHASE MITIGATION

As mentioned earlier in the impact section, the construction of the project will cause PM10 emissions, which will add to the existing violations of the ambient PM10 air quality standard. Staff believes this is a potentially significant impact. Therefore, the project PM10 emission impacts due to its construction is significant. Staff believes the implementation of the staff recommended construction mitigation measures (listed in the Staff Proposed Mitigation Section) will be effective in reducing the short-term impacts of the project to a level of less than significance.

OPERATION PHASE MITIGATION

Staff believes that the proposed dry low-NOx and SCR system control, the CO oxidation catalyst system, and the use of the hybrid cooling tower that is also equipped with high efficient drift eliminator represent a feasible mitigation, and are consistent with the District, the ARB and EPA recommendations for BACT.

PM10 MITIGATION

As mentioned in the Setting section, the Burney area is unique in that its air quality, during the winter months, is not significantly affected by transport from the Sacramento Valley air basin, which includes Redding. Nevertheless, the Burney area is experiencing regular exceedances of the state 24-hour PM10 standard, especially during the cold winter months. Therefore, staff believes that emissions reductions must be provided from the local area to effectively mitigate the facility's PM10 emissions impacts.

The applicant's proposed PM10 emission reductions from road paving are effective only during the dry months of the year when fugitive dust is created by vehicles traveling on the local unpaved roads. During the winter months no PM10 emission reductions from road paving would be realized because the soil is wet or the road is covered with snow. Thus the emission reductions from road paving are not effective in reducing the impacts from the facility during the winter months.

OFFSETS FOR OZONE PRECURSORS

As mentioned in the impact section, staff does not believe that the project will contribute significantly to the ozone formation in the Burney area. However, ozone precursor emission reduction credits from the Sierra Pacific in Anderson are provided to meet the requirements of the Shasta County Air Quality Element Policies.

STAFF PROPOSED MITIGATION

To mitigate the project's PM10 emission impacts during construction, staff recommends that the following control measures be implemented:

- Frequent watering of unpaved roads and disturbed areas (at least twice a day).
- Limit speed of vehicles on the construction areas to no more than 10 MPH.
- Use tire washing and gravel ramps prior to entering a public roadway to limit accumulated mud and dirt deposited on the roads.
- Treat the entrance roadways to the construction site with soil stabilization compounds.
- Place sandbags adjacent to roadways to prevent run-off to public roadways.
- Install windbreaks at the windward sides of construction areas prior to the soil being disturbed. The windbreaks shall remain in place until the soil is stabilized or permanently covered.
- Use of dust sweeping vehicles at least twice a day to sweep the public roadways that are used by construction and worker vehicles.
- Sweep newly paved roads at least twice weekly.
- Limit on equipment idle times (no more than fifteen minutes).
- Use of electric motors for construction equipment when feasible.
- Apply covers or dust suppressants to soil storage piles and disturbed areas that remain inactive over two weeks.
- Pre-wet the soil to be excavated during construction.
- Use of oxidizing soot filters on all suitable, large off-road construction equipment with an engine rating of at least 100 bhp.

During the operation of the project, staff recommends that the applicant implement a combination of road paving and retrofitting of residential wood burning devices used in the Burney area as mitigation measures. The emission reductions achieved from paving of road will be used to offset the proposed facility's PM10 emissions for the three quarters where the weather is dry. This is to satisfy the District General Policy 2e. For the three months in winter when there are rain and snow and when the area PM10 air quality suffered, the staff recommended wood stove change-out program will mitigate the proposed TMPP's PM10 contribution to a level of insignificance. Staff recommended PM10 mitigation is discussed in detail below.

ROAD PAVING

For road paving, staff recommends that the roads identified in AIR QUALITY Table 10, be considered for paving to offset the emission increases from the proposed project. According to the applicant survey results and estimates, the identified roads in **AIR QUALITY Table 10** would generate approximately 666 TPY of PM10, which are adequate to cover 135 TPY of PM10 emission liability from the project.

AIR QUALITY Table 10
Staff Recommended Roads to be Paved for Offsets

Candidate Roads	Average Daily Trips	Length Miles	Available PM10 Emission Reduction Credits Ton per Year
Goose Valley	153	5.9	260
Tamarack	26	5.5	34
Mountain View	168	4.2	273
Estes Avenue	69	0.05	12.2
Vallejo Street	81.5	0.10	1.4
Bailey Avenue	64	0.10	0.85
Apple Orchard Lane	24	0.85	6.1
Ivan Marx Road	97	0.40	6.5
Pit River Casino	691		37.8
Wasburn Road	213	0.10	7.8
Cottonwood East	174	0.13	8.9
Cottonwood West	174	0.2	10.3
Fairfield	74	0.31	7.4
Total Available			***666***

WODDSTOVE REPLACEMENT PROGRAM

In addition to road paving staff suggests the applicant subsidize the replacement of existing residential wood stoves and fireplaces with EPA phase II certified wood stoves and fireplace inserts for willing residents of the town of Burney. This would mitigate the project's direct and secondary PM10 contribution, of approximately 45 tons, to the wintertime PM10 problem, which is caused, in large part, by residential wood burning.

HOW THE PROGRAM WORKS:

Basically, the new wood stoves, called "EPA Phase II Certified Units", burn more cleanly and efficiently than older units that are not EPA certified. Thus, replacing the older units with the new units will result in both lower emissions and a reduction in the amount of wood being burned. These emission reductions will mitigate part of the project's PM10 and volatile organic compound emissions.

Based on the annual quantity of wood burned per household collected at various workshops, staff estimates that TMPP needs to replace between 389 to 455 wood stove units in the Burney area to mitigate the project PM10 contribution to a level of less than significance. The exact number of wood stove will be determined later after the applicant decides on which turbine model (Westinghouse or GE) to be selected (see Appendix B for staff calculations). A quick screening of local wood stove suppliers in Sacramento and Burney indicate that it would cost between $900.00 to $1,500.00 to replace an existing wood stove or modify a fireplace with a certified unit. Using an average cost of $1,225 per unit, staff estimates that the cost for replacement of 455 units could reach upward to $600,000.Staff suggests that the applicant design and market a program, which would achieve the following goals:

- The program will last for five years or until 455 units have been installed, whichever comes first.
- Any funds remaining will be used for road paving as designated by the California Energy Commission in consultation with the Shasta Air Quality Management District, or for other measures as agreed to by those parties and TMPP.
- The program is strictly on a voluntary basis to willing residents of Burney and Johnson Park.
- Each resident participating in the program will be eligible to receive an EPA Phase II Certified wood stove unit installed, free of charge or up to a total of $1,225.00 cost toward a more expansive model, whichever is less.
- Priority will be given to retailers and licensed installers who have businesses in the Burney area to sell and install the new wood stoves, and remove the old wood stoves.
- Each resident participating in the program would only do business with the retailer and the professional, licensed installer.
- The retailer must certify that he or she has rendered all old wood stoves replaced non-operative by permanent removal of the stove doors.
- The retailers are required to keep records of old wood stove units being removed and installation of the new units, and submit those records to TMPP on a weekly basis for reimbursement.

Staff has estimated that in addition to reducing the direct PM10 emissions, the 455 new wood stove units would also reduce approximately 115 TPY of VOC emissions that could be emitted to the atmosphere (see Appendix B). It should be noted that the type of VOC that would typically be emitted from wood stoves are those that are converted to carbon-based PM10 on a pound per pound basis. By reducing these 115 TPY of the wood stove VOC emissions, staff believes that these emissions reductions will mitigate any secondary PM10 contribution from the power plant to a level of insignificance.

In addition to reducing the PM10 and VOC emissions, the certified wood stoves and fireplace inserts also improve the efficiency of the wood burning process, which results in a reduction in the amount of wood being burned. This will also reduce emissions of NO2, and SO2, all of which are precursors to PM10 formation.

COMMUNITY CONCERNS

During various workshops, staff has received many comments from the public, which staff is attempting to respond as follows:

1. THE PROJECT HAS BEEN EVALUATED WITH OLD AIR QUALITY DATA

The public has concerns that because the air quality data used in the applianct's analysis were collected more than seven years ago, it does not represent the current condition at the site. Therefore, if the project is evaluated using this older air quality data, the conclusion that the project will either cause or not cause a significant air quality is meaningless.

STAFF RESPONSE:

Staff agrees that the available ambient air quality data are old, however, staff does not believe that collection of a year's worth of ambient data will reveal new information as to the air quality situation at the site. Staff has provided a qualitative analysis of the representativeness of the available ambient air quality data in the "EXISTING AMBIENT AIR QUALITY" section of this analysis, taking into account the general trend of the air quality, the population growth, and the emission inventory from 1990 to 1996. Staff concluded that the existing ambient air quality data, even though old, reasonably depicts the current conditions of the area.

In addition, staff has evaluated the project with the assumptions that the area is non-attainment for PM10 and thus, concluded that all TMPP emission increases will need to be mitigated. Staff recommends that mitigation in the form of emission reductions be required to reduce the project impacts to a less than significant level (see "MITIGATION" and STAFF PROPOSED MITIGATION" sections).

In addition to this recommendation, to allay concerns about the impacts of the project, staff recommends a requirement that the applicant conduct a five-year air quality study to collect ambient air quality data for ozone and PM10; two years prior to construction, and three years after project operation. This air quality study would determine any appreciable changes to the air quality in the area. The applicant has indicated that they will accept such conditions if staff recommends it.

2. THE METEOROLOGICAL DATA ARE NOT REPRESENTATIVE

The public raised concerns that the meteorological data used in the air quality impacts analysis do not represent the condition of the area, and recommends that a one year pre-construction air quality study be performed.

STAFF RESPONSE:

In response to the concerns of the public, staff recommended that the applicant provide an impact analysis using the artificially severe weather conditions, i.e., those conditions that would result in the highest possible impacts. Even after incorporating these artificially severe weather conditions, modeling indicates that the project is not expected to cause any new violations of any ambient air quality standard, or violate any PSD increment consumption. [An increment consumption is an allowable impact that a project can create without a significant deterioration in the ambient air quality conditions of an area]. Therefore, because of the air quality analyses described above, indicated the project would not cause any impacts under most probable met conditions actual met data is not required and the need for one year of pre-construction air quality data is not warranted.

3. *THE PROJECT CUMULATIVE IMPACTS ANALYSIS IS DEFICIENT*

The public raised concerns that the cumulative impact analysis does not take into account many new major sources and major modifications to other sources in the vicinity of the project.

STAFF RESPONSE:

Staff has reviewed emission inventory data and the permit files in the "CUMULATIVE IMPACTS" section. Staff believes that conclusion about the cumulative impact analysis of the project and other sources in the area is accurate.

4. *LACK OF LOCAL OFFSETS*

The public concerns that the project did not secure local emission reductions to offset the facility's new criteria air pollutant emissions.

STAFF RESPONSE:

As mentioned in the "MITIGATION" section, staff believes that a combination of road paving and retrofitting 455 local residents' wood stoves with EPA certified wood stoves will mitigate the project PM10 emissions to a level of less than significant.

As for ozone, staff believes that the project ozone impacts to the local area are not significant (see "CUMULATIVE IMPACTS" section). The applicant has not been able to locate any potential seller of emission reduction credits in the Burney area; therefore, they proposed to offsets NOx and VOC (ozone precursors) emission reduction credits from Anderson, which will prevent further degrading of ozone air quality standard in the region.

5. *LACK OF APPLICATION OF STATE OF THE ART CONTROL TECHNOLOGY*

Intervenors, as well as some residents of the community express a concern that the project should be equipped with the SCONOx emission control system.

STAFF RESPONSE

There is some debate over whether SCONOx is technically feasible when applied to a combustion turbine as large as the GE Frame 7F. ABB Environmental has issued a press release stating that the SCONOx technology is commercially ready for any size turbine. However, the largest turbine that SCONOx has been applied to is a GE LM2500, approximately 25 MW in capacity of about 1/6th the size of the proposed TMPP. The Otay Mesa Power Project (which will use Frame 7F turbines) has issued a press release stating that they intend to use the SCONOx technology as their primary NOx and CO control method. The recently (March 8, 2000) filed AFC for the Nueva Azalea Project also proposes to use the SCONOx technology.

SCONOx would not require an oxidizing catalyst or the use of ammonia to control NOx and CO emissions. SCONOx technology employs a reactive catalyst that must be regenerated on a regular basis. The catalyst reacts with CO and NO to form CO_2, which is emitted, and NO_2, which is absorbed on the surface of the catalyst until it is saturated. Prior to saturation, the catalyst is regenerated. This is done by sealing off the catalyst from the exhaust stream by a pair of mechanical louver doors and subjecting it to a mixture of natural gas and steam, which forms hydrogen to produce elemental nitrogen and CO_2, which are emitted through the stack.

ABB Environmental requires that the catalyst in each module be removed and put through a regenerative bathing process once a year. There is some concern that this bathing process may result in an additional hazardous waste stream. The time required for this process is not clearly known, but it is likely to be approximately 1-2 weeks. Also, there may be a requirement that liquefied natural gas be stored on site to be used during the regular regeneration process of the catalyst throughout the year.

ABB Environmental has submitted to TMPP a proposal for the SCONOx system. ABB proposes 15 SCONOx modules in an assembly to control NOx and CO to 2 ppm each, for each Frame 7F turbine with a capital cost of $26 million (TMPP, 2000c).

ABB Environmental has tested the louver doors used by each module under both static and dynamic thermal conditions similar to those found in the Frame 7F exhaust stream. However, the testing did not include realistic flow or emission conditions that can be expected in an actual installation on a F size turbine. Control algorithms have not yet been developed, nor tested for the 15 or more SCONOx modules. Due to the lack of appropriate testing and information, some HRSG manufacturers have expressed reluctance to issue guarantees for their equipment if SCONOx is installed (Beck, 2000).

Staff believes that the SCONOx technology is a proven NOx and CO emission abatement system without the use of ammonia. Staff also believes that the SCONOx technology is not applicable for project such as TMPP. Staff reaches this conclusion based on three points:

First, the SCONOx performance guarantee requires an inlet NOx concentration of 9 ppm, which is the lowest level achieved by a combustion turbine/dry low NOx system. Because a typical turbine's NOx emissions could emit a NOx concentration as high as 15 ppm, the SCONOX guarantee of 2 ppm NOx emission is not applicable.

<u>Verification:</u> Second, the guarantee for the SCONOx catalyst is voided if it is exposed to liquid water. TMPP has asked ABB to provide a proposal for a heat recovery steam generator/SCONOx system because steam generator vendors cannot guarantee the performance of their steam generators due to the possible uneven heat stress cause by the damper system for SCONOx. The ABB proposal is only for the SCONOx system, which voids all guarantee if the catalyst is exposed to liquid water. If the damper system actually causes an uneven heat distribution in the heat recovery steam generator, water tubes may experience heat stress and break. This would send liquid water to the SCONOx catalyst, which void the warrantee and render the system inoperable.

Third, SCONOx offers a 0.5 ppm NOx improvement (2 ppm from the proposed 2.5 ppm) while potentially having many NOx emission excursions, which may require more startup and shutdowns of the turbines, and can result in higher overall annual emissions.

COMPLIANCE WITH LORS

FEDERAL

The applicant has submitted to the District an application for the federal PSD permit. The District has issued a Final Determination of Compliance (FDOC) on May 26, 2000. The FDOC will also serve as the preliminary PSD permit.

In addition, the applicant is required to obtain from the District a Federal Operating Permit (Title V) within one month after the project starts to operate. The applicant is also required to submit an acid rain application (Title IV) to the District at least 24 months prior to the project generating electricity. Compliance with both of these federal titles will be determined at a later date.

STATE

The project with the offsets that are be necessary for the project to secure a Determination of Compliance from the District, will comply with Section 41700 of the California Health and Safety Code. The project will be fully mitigated and therefore would not cause any injury, detriment, nuisance or annoyance to the public.

LOCAL

The District has issued a Final DOC (October 10, 2000), which states that the TMPP project is expected to comply with all applicable District Rules and Regulations, and that all offsets will be provided prior to start construction of the project. (SCAQMD, 2000)

CONCLUSIONS AND RECOMMENDATIONS

The project emissions will be fully offset, and the project will incorporate BACT (SCR and CO oxidation catalyst systems) in accordance with the District NSR requirements. The project will not cause new violations of any NO2, SO2, or CO ambient air quality standards, and therefore, its NOx, SOx and CO emission impacts are not significant.

Staff recommends that addition of a few more restrictions on construction activities, which are described in Condition of Certification AQ-24 (k), (l), and (m). In addition, staff recommends the addition of Condition of Certification AQ-25 to address the PM10 and NOx emissions from large construction equipment. Staff believes that with these two additions, the project's construction impacts on PM10 will be mitigated to a level that is not significant.

The project's directly emitted PM10 emissions can, if left unmitigated, contribute to violations of the state 24-hour PM10 standard, especially during the winter season. However, with the offsets and local emissions mitigation measure being provided [in the form of road paving and wood stove replacement] the potential for direct and secondary PM10 emission impacts is reduced to a level will not be significant.

To address the community concerns over the lack of current ambient air quality data in Burney area, staff recommends the addition of Condition of Certification AQ-28. This condition would require the applicant to collect five continuous calendar years of ambient concentrations of NOx and PM10 in Burney. Two of which years will be prior to actual operation of the proposed project, and three years will be after the actual operation of the project. This condition of certification will also assist in verification of compliance with the District's Condition of Certification AQ-60, which requires that fugitive emissions from the facility not cause a new violation of the ambient air quality standards.

The District has submitted a Final Determination of Compliance that concludes that the TMPP project would comply with all applicable District rules and regulations and therefore has proposed a set of conditions of approval. These are presented here as Conditions AQ-1 to AQ-24, AQ-26, AQ-27, and AQ-29 to AQ-61.

CONDITIONS OF CERTIFICATION

AQ-1. This Authority to Construct (PSD Permit) is issued in accordance with the rules and regulations of the District and pursuant to the delegation of PSD authority by the Environmental Protection Agency (EPA), Region IX, on July 8, 1985. If any provision of this permit is found invalid, such finding shall not affect the remaining provisions. Note: This permit does not constitute a final decision regarding the Final PSD Permit. This is due to the fact that the USEPA/USFWS Endangered Species Act consultation related to the potential impacts of the proposed project to listed endangered species is in process. That process is expected to be completed with USFWS issuance of a Biological Opinion. The District will issue the decision on the Final ATC/PSD permit after the Section 7 consultation process is completed and after USEPA has determined that issuance of the permit will be consistent with USEPA's obligations under the Endangered Species Act. Accordingly, any PSD conditions in this permit (as noted following each condition) are not final at this time, and the District will issue the Final ATC/PSD permit conditions for the subject project, if appropriate to do so, upon completion of the consultation process and USEPA's determination. [Non-PSD]

Verification: Not necessary.

AQ-2. The owner/operator must obtain an Authority to Construct (PSD Permit) from the District and certification from the California Energy Commission (CEC) prior to commencing construction on the project site. If a permit is required from the U.S. Fish & Wildlife Service or the California Department of Fish and Game regarding impacts to endangered species, then the owner/operator shall be responsible for assuring that these requirements are met to the satisfaction of the above-named agencies and EPA Region IX as required by law. [PSD]

Verification: The applicant shall provide the District and the CEC Compliance Project Manager (CPM) copy of the final PSD permit within one week from the date of its issuance.

AQ-3. In the event of any changes in control or ownership of facilities to be constructed or modified, this Authority to Construct (PSD Permit) shall be binding on all subsequent owners and operators. The applicant shall notify the succeeding owner and operator of the existence of this Authority to Construct (PSD Permit) and its conditions by letter, a copy of which shall be forwarded to the Air Pollution Control Officer (APCO) of the Shasta County Air Quality Management District (District), the California Air Resources Board (CARB), and the EPA. [PSD]

Verification: Ninety (90) days prior to change of control or ownership of the facility, the owner shall provide the CEC CPM a copy of the District approved "Change of Ownership" and a copy of the new Permit to Operate of the facility.

AQ-4. Equipment is to be maintained so that it operates as it did when the permit was issued.

Verification: See Verification of Condition AQ-58.

AQ-4. If construction has not physically commenced on the site within two (2 years) from the date of issuance of this permit, the Authority to Construct (PSD Permit) shall become invalid in accordance with District Rule 2:12. [Non-PSD]

Verification: Not necessary.

AQ-5. Acceptance of this permit is deemed acceptance of all conditions as specified. All equipment, facilities, and systems shall be designed and operated in a manner that maintains compliance with the conditions of this permit, applicable provisions of 40 CFR Parts 52, 60, 61, 68, 72 and any other applicable local, State, or Federal regulations. Failure to comply with any condition of this permit or the Rules and Regulations of the District shall be grounds for revocation, either by the APCO or the District Hearing Board. [PSD]

Verification: Not necessary.

AQ-6. The District reserves the right to amend this permit, if the need arises, in order to insure compliance of this facility with applicable local, State, or Federal regulations, or to abate any public nuisance. [Non-PSD]

Verification: The project owner shall seek prior approval from the District and CEC CPM prior to any modification that is deemed necessary by the District to comply with Condition AQ-6.

AQ-7. Periods of excess emissions, upsets, breakdowns, or malfunctions shall be reported to the District, in accordance with District Rule 3:10, within four hours of occurrence. In no event shall the equipment be operated with the emission control equipment in a malfunctioning condition beyond the end of the work shift or 24 hours, whichever occurs first. [Non-PSD]

Verification: Not necessary.

AQ-8. This facility is subject to all applicable requirements of the Air Toxics "Hot Spots" Information and Assessment Act of 1987, as cited in California Health and Safety Code Sections 44300 et seq. [Non-PSD]

Verification: Project owner shall prepare and submit to the District a Toxic Hot Spots emission inventory by the first month of August following the first full calendar year of facility operational history.

AQ-9. This facility is subject to the applicable provisions of Title V of the Federal Clean Air Act of 1990. Within twelve (12) months after operational startup of the facility, the owner/operator shall apply for a Title V Federal Operating Permit. [Non-PSD]

Verification: The project owner shall apply for, and shall provide the CEC CPM a copy of the Title V Federal Operating Permit within 30 days from the date of receiving such permit.

AQ-10. The right of entry described in California Health and Safety Code Section 41510, Division 26, shall apply at all times. The Regional Administrator of the EPA, the Executive Officer of the California Air Resources Board, the APCO, and/or their authorized representatives, upon the presentation of credentials shall be permitted:

a. to enter upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this Authority to Construct; and
b. at reasonable times to have access to and copy any records required to be kept under the terms and conditions of this Authority to Construct; and
c. to inspect any equipment, operation, or method required in this Authority to Construct; and
d. to sample emissions from any and all emission sources within the facility.

[Non-PSD]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, EPA or CEC.

AQ-11. The owner/operator shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, continuous emissions records, excess emissions, breakdowns, etc.), source test and analytical records, emission calculation records, records of plant upsets and related incidents. All records and emission test results requested to be kept under the terms and conditions of this Authority to Construct shall be made available to the District staff upon request. [Non-PSD]

Verification: See verification for Condition AQ-10.

AQ-12. The operating staff with management authority at this facility shall be advised of and be familiar with all the conditions of this permit. [Non-PSD]

Verification: Not necessary.

AQ-13. References to rules, regulations, etc., within this permit shall be interpreted as referring to such rules and regulations in their present configuration and language as of the date of issuance of this permit. [Non-PSD]

Verification: Not necessary.

AQ-14. The owner/operator shall provide the following Best Available Mitigation Measures in accordance with the Air Quality Element of the Shasta County General Plan upon startup:

a. On-site services such as food vending machines as appropriate and in compliance with local development regulations.
b. Mobile lunch service to serve the facility if available.
c. On-site pedestrian facility improvements such as walking paths and building access which are physically separated from street and parking lot traffic.
d. A parking lot design that does not impede a clear, direct pathway for safe, easy movement of pedestrians.
e. Adequate bicycle storage/parking facilities at a minimum of one bicycle space for every 20 automobile spaces.
f. Preferential parking spaces for carpools and van pools.

[Non-PSD]

Verification: At least six months prior to construction of the facility, the project owner shall provide the District and CEC CPM detailed building plan showing that the facility will be built in accordance with the provisions of the Shasta County General Plan.

AQ-15. As per California Health & Safety Code Section 41700, no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injure or damage to business or property. [Non-PSD]

Verification: See Condition AQ-58 and its verification.

AQ-16. The owner/operator shall provide to the California Energy Commission (CEC) Construction Project Manager (CPM) a copy of the facility Permit(s) to Operate within fifteen (15) days of issuance. [Non-PSD]

Verification: Not necessary.

AQ-17. The owner/operator shall certify compliance with the requirements of 40 CFR Part 68 Risk Management Plan requirements as applicable as part of the compliance certification required by Title V of the Federal Clean Air Act. [Non-PSD]

Verification: Ninety (90) days prior to start construction of the project, the project owner shall provide the District and the CEC CPM a copy of the Risk Management Plan.

AQ-18. The owner/operator shall meet the provisions of the Federal Acid Rain Program (Title IV) program by filing for an Acid Rain permit 24 months before operational startup and by certifying NO_X and O_2 CEMs within 90 days after operational startup. [Non-PSD]

Verification: No more than thirty (30) days after receiving the federal Acid Rain permit, the project owner shall provide the District and the CEC CPM a copy of such permit.

AQ-19. At least 30 days prior to commencement of construction, the owner/operator shall provide the District and the CEC CPM with written documentation that the following emission offsets have been acquired or that binding contracts to secure such offsets have been entered into. All emission offsets shall also meet applicable conditions of certification applying to offsets as required by the CEC.

If General Electric PG7241FA gas turbines are utilized for the project, the total NOx Emission Reduction Credits (ERC) purchased for the project shall be 144 tons/year (71,014 pounds in Calendar Quarter I, 71,803 pounds in Calendar Quarter II, 72,592 pounds in Calendar Quarter III, and 72,592 pounds in Calendar Quarter IV). The total VOC ERCs purchased for the project shall be 41 tons/year (20,219 pounds in Calendar Quarter I, 20,444 pounds in Calendar Quarter II, 20, 668 pounds in Calendar Quarter III, and

20,668 pounds in Calendar Quarter IV). The ERC's shall be purchased from Sierra Pacific Industries, Inc. available on Certificate No. 97-ERC-02 previously entered in the District ERC bank.

If Westinghouse 501F gas turbines are utilized for the project, the total NOx Emission Reduction Credits (ERC) purchased for the project shall be 130 tons/year (64,116 pounds in Calendar Quarter I, 64,818 pounds in Calendar Quarter II, 65,534 pounds in Calendar Quarter III, and 65,534 pounds in Calendar Quarter IV). The total VOC ERCs purchased for the project shall be 65 tons/year (32,058 pounds in Calendar Quarter I, 32,409 pounds in Calendar Quarter II, 32,656 pounds in Calendar Quarter III, and 32,656 pounds in Calendar Quarter IV). The ERC's shall be purchased from Sierra Pacific Industries, Inc. available on Certificate No. 97-ERC-02 previously entered in the District ERC bank.
[Non-PSD]

Verification: Not necessary.

AQ-20. At least 30 days prior to commencement of construction, the owner/operator shall provide the District and the CEC CPM with written documentation that the following emission offsets have been acquired or that binding contracts to secure such offsets have been entered into except as noted in b.(2) below. All emission offsets shall also meet applicable conditions of certification applying to offsets as required by the CEC.

Paving of unpaved portions of any of the following roads in the Burney area shall be provided in order to create an emission offset of either 138 tons per year (based on use of General Electric PG7241FA turbines @ 75% of the project's 184 tons/year PM_{10} emissions) or 115.5 tons per year (based on use of Westinghouse 501F turbines @ 75% of the project's 154 tons/year PM_{10} emissions) quantified in a manner acceptable to the APCO and CEC CPM by using Sections 13.2.1 and 13.2.2 of EPA's Compilation of Air Pollution Emission Factors AP-42 document:

ROADS
Goose Valley Road
Estes Avenue
Fairfield Street
Goose Creek Road
Vallejo Street
Apple Orchard Lane
Bailey Ave.
Cottonwood Street
Tamarack Road
Washburn Road
Ivan Marx Road
Pit River Casino Parking Lot
Mountain View Road

Note: The road selection and distance of the roads to be paved above may be changed upon approval of the APCO and the CEC CPM provided that the total PM_{10} offset remains the same. A copy of executed legally binding contracts between the applicant and Shasta County or any applicable road maintenance district shall be provided to the District and the CEC CPM at the conclusion of paving, ensuring the maintenance of said roads or paved areas.
[Non-PSD]

Verification: No more than thirty (30) days after paving the roads, the project owner shall provide pictures of before and after road paving. No later than ninety (90) days prior to start up of the project, the project owner shall provide documentation of the length of each road to be paved for emission reduction.

AQ-21. A fireplace retrofit/woodstove replacement fund shall be made available on a first-come, first-serve basis to finance a five-year voluntary woodstove replacement/fireplace retrofit program which shall provide a minimum PM_{10} emission offset of either 46 tons/year (based on use of General Electric PG7241FA turbines @ 25% of the project's 184 tons/year PM_{10} emissions) or 38.5 tons/year (based on use of Westinghouse 501F turbines @ 25% of the project's 154 tons/year PM_{10} emissions). The replacement fund shall pay for the retrofit/ replacement costs of at least 465 (based on use of General Electric PG7241FA turbines) or 389 (based on use of Westinghouse 501F turbines) current non-EPA certified fireplaces and woodstoves (up to a maximum of $1225 for each retrofit/replacement) with either an EPA-certified solid fuel heating device, a propane heating device, or a natural gas heating device. The fund shall be capable of being drawn upon in any year of the five year program and as allowed by conditions of CEC certification until the fund is depleted. Each resident participating in the retrofit/replacement program would only do business with the retailer and a professional, licensed installer. Payments shall be made to vendors or contractors who agree to participate in the program and who submit certification that the retrofit/replacement was permanent (by dedicated natural gas, or propane fuel, or permanent removal of the woodstove doors and proper recycling of the old stove), conformed to the program, and resulted in direct savings to the consumer/end user. Quarterly status reports on the program and the status of the reimbursements and remaining fund available shall be made to the APCO and the CEC Construction Project Manager. For the first three years of the program, homes and businesses located within a six-mile radius of the proposed facility will be eligible to participate in the program. After the initial three years of the program period expire, if the fund has not been exhausted, homes and businesses within a fifteen-mile radius of the TMPP facility will be eligible to participate in the program in the fourth and fifth years. If the fund still has not been exhausted after the fifth year, the remaining amount will either be used to pave additional roads or be paid to Shasta County for use in PM_{10} emissions reduction programs administered by the Shasta County AQMD. The fund shall be audited annually and a report of program activity shall be submitted to the District and CEC project manager each year for review. [Non-PSD]

Verification: No later than 30 days prior to commencement of construction, the project owner shall provide the District and the CEC CPM a copy of the approved wood stove replacement program. In addition, the project owner shall submit to the District and CEC CPM a copy of the annual audit report by January 31, of each subsequent year.

AQ-22. The facility shall comply with all portions of the Federal New Source Performance Standards 40 CFR 60, Subpart A (General Provisions), Subpart Da (Standards of Performance for Electric Utility Steam Generating Units), and Subpart GG (Standards of Performance for Stationary Gas Turbines). Notification with respect to commencement of construction (30 day notice), anticipated date of startup (30 day notice), actual date of startup (within 15 days), and modifications which could increase emission rates (60 days or as soon as practicable) shall be provided to the EPA Administrator in accordance with 40 CFR 60.7. [PSD]

Verification: Not necessary.

AQ-23. This facility is subject to the applicable provisions of the National Emission Standards for Hazardous Air Pollutants for Combustion Turbines when the Standards in their final form are promulgated by EPA. Emission limits stated in the above provisions, however, do not supersede more stringent limits found in other conditions of this permit. [PSD]

Verification: Not necessary.

CONSTRUCTION PHASE CONDITIONS

AQ-24. During construction of this facility, the following fugitive emission control measures shall be implemented at the plant site:

(a) Suspend all land clearing, grading, earth moving, or excavation activities when winds (including instantaneous gusts) exceed 20 miles per hour.
(b) Apply water to active construction sites and unpaved roads at least twice daily to control fugitive dust.
(c) Apply sufficient water or dust suppressants to all material excavated, stockpiled, or graded to prevent fugitive dust from leaving the property boundaries and causing a public nuisance or a violation of an ambient air standard.
(d) Apply a non-toxic solid stabilizer to all inactive construction areas (previously graded areas which remain inactive for 96 hours).
(e) No on-site vehicle shall exceed a speed of 10 miles per hour on unpaved roads or areas.
(f) All trucks hauling dirt, sand, soil, or other loose material will be watered or covered and will maintain at least two feet of freeboard to prevent a public nuisance.
(g) Install wheel washers where vehicles enter and exit unpaved roads onto paved roads, or wash off trucks and any equipment leaving the site each trip.

(h) Sweep streets with a water sweeper at the end of each day if visible soil materials are carried onto adjacent public or private paved roads.
(i) Re-establish ground cover on the construction site through seeding and watering as soon as possible, but no later than final occupancy.
(j) Implement all dust control measures in a timely and effective manner during all phases of project development and construction.
(k) Place sandbags adjacent to roadways to prevent run off to public roadways.
(l) Install wind breaks at the windward sides of construction areas prior to the soil being disturbed. The wind breaks shall remain in place until the soil is stabilized or permanently covered.
(m) ***Limit construction vehicles and equipment idle time to no more than 15 minutes.***
[Non-PSD]

Verification: The project owner shall maintain a daily log of water truck activities, including record of the frequency of public road cleaning. These logs and records shall be available for inspection by the CPM during the construction period. The project owner shall identify in the monthly construction reports, the area(s) that the project owner shall cover or treat with dust suppressants. The project owner shall make the construction site available to the District staff and the CPM for inspection and monitoring.

AQ-25. The project owner shall ensure that all heavy earthmoving equipment including, but not limited to, bulldozers, backhoes, compactors, loaders, motor graders and trenchers, and cranes, dump trucks and other heavy duty construction related trucks, have been properly maintained and the engines tuned to the engine manufacturer's specifications. The project owner shall also install oxidizing soot filters on all suitable construction equipment used either on the power plant construction site or associated linear construction sites. Where the oxidizing soot filter is determined to be unsuitable, the owner shall install and use an oxidizing catalyst. Additionally, the project owner shall employ high pressure fuel injection, timing retardation, and reduced idle time on all suitable construction equipment. Suitability is to be determined by an independent California Licensed Mechanical Engineer or a Qualified Environmental Professional who will stamp and submit for approval an initial and all subsequent Suitability Reports as necessary containing at a minimum the following:

Initial Suitability Report:

1. The initial suitability report shall be submitted to the CPM for approval 60 days prior to the relevant equipment being used at the project site.
2. A list of all fuel burning, construction related equipment used,
3. a determination of the suitability of each piece of equipment to work appropriately with an oxidizing soot filter, or an oxidizing catalyst,

4. if a piece of equipment is determined to be suitable, a statement by the equipment or catalyst manufacturers, the independent California Licensed Mechanical Engineer, or a Qualified Environmental Professional that the oxidizing soot filter has been installed and is functioning properly,

5. if a piece of equipment is determined to be unsuitable, an explanation by the equipment or catalyst manufacturers, the independent California Licensed Mechanical Engineer, or a Qualified Environmental Professional as to the cause of this determination, and

6. ***a statement by the equipment or catalyst manufacturers, the California Licensed Mechanical Engineer, or a Qualified Environmental Professional as to the suitability of using high-pressure fuel injectors, timing retardation and/or reduced idle time on all construction equipment after the installation of either oxidizing soot filters or oxidizing catalysts.***

Subsequent Suitability Reports

- ***If a piece of construction equipment is subsequently determined to be unsuitable for an oxidizing soot filter after such installation has occurred, the filter may be removed immediately. However notification must be sent to the CPM for approval containing an explanation for the change in suitability within 10 days.***
- ***Changes in suitability are restricted to three explanations which must be identified in any subsequent suitability report. Changes in suitability may not be based on the use of high-pressure fuel injectors, timing retardation and/or reduced idle time.***

    1. ***The oxidizing soot filter is reducing normal availability of the construction equipment due to increased downtime, and/or power output due to increased back pressure by 20% or more.***
    2. ***The oxidizing soot filter is causing or reasonably expected to cause significant damage to the construction equipment engine.***
    3. ***The oxidizing soot filter is causing or reasonably expected to cause a significant risk to nearby workers or the public.***

Verification: *The project owner shall submit to the CPM, via the Monthly Compliance Report, documentation, which demonstrates that the contractor's heavy earthmoving equipment is properly maintained and the engines are tuned to the manufacturer's specifications. The project owner shall maintain all records on the site for six months following the start of commercial operation. The project owner will submit to the CPM for approval, the initial suitability report stamped by an independent California Licensed Mechanical Engineer or a Qualified Environmental Professional, 60 days prior to breaking ground on the project site. The project owner will submit to the CPM for approval, subsequent suitability reports as required, stamped by an independent California Licensed Mechanical Engineer or a Qualified Environmental Professional, no later than 10 working day following a change in the suitability status of any construction equipment.*

OPERATING CONDITIONS

AQ-26. Combustion turbines and duct burners shall be exclusively fueled with California PUC pipeline quality natural gas with a sulfur content not to exceed 0.4 grain per 100 standard cubic feet. [PSD]

<u>Verification:</u> The project owner shall maintain, on a monthly basis, a laboratory analysis showing the sulfur content of natural gas being burned at the facility. The monthly sulfur analysis shall be incorporated into the monthly compliance reports as required in Condition AQ-58 and its verification.

AQ-27. A continuous monitoring system shall be installed and maintained to monitor and record the fuel consumption being fired in each power train. The system must be accurate to within plus or minus five (5) percent. [PSD]

<u>Verification:</u> Six month prior to start construction of the project, the project owner shall submit the final selection of turbines and associated equipment, and monitoring and data acquisition equipment, including all drawing and manufacturer data to the District, the EPA and CEC CPM for approval.

AQ-28. The project owner shall collect ambient concentration of ozone and PM10 at the existing Burney monitoring station for a continuous period of not exceeding five calendar years. Two years of which will be prior to actual operation of the facility.

<u>Verification:</u> See verification of Condition AQ-27.

AQ-29. A continuous monitoring system complete with ammonia flow meter and injection pressure indicator shall be installed and maintained to monitor and record the ammonia injection rate on each SCR system. The system must be accurate to within plus or minus five (5) percent. [PSD]

<u>Verification:</u> See verification for Condition AQ-27.

AQ-30. Instrument shall be installed and maintained on each gas turbine power train to measure electrical energy production. [Non-PSD]

<u>Verification:</u> See verification for Condition AQ-27.

AQ-31. Prior to the initial firing of any fuel through either power train, a continuous emission monitoring system (CEM) shall be installed, calibrated, and operated on each HRSG exhaust to measure volumetric flow and concentrations of NOx and CO, and percent O2. The system shall meet monitoring and quality assurance specifications as required by *40 CFR 60.13; 40 CFR 60*, Appendix B, Specifications 2, 3, 4, 6; and *40 CFR 60*, Appendix F except that due to the extremely low permitted limits for NOx and CO concentrations, the relative accuracy procedure shall be defined as conducting a complete CEMS status check on an annual basis following the manufacturer's written instructions. The check should include operation of the light source, signal receiver, timing mechanism functions, data acquisition and data reduction functions, data recorders, mechanically operated functions (mirror movements, calibration gas valve operations, etc.), sample filters, sample line heaters, moisture traps, and other related functions of the CEMS, as applicable. The monitoring systems must also successfully pass the calibration and drift requirements of the equipment manufacturer. (Reference *40 CFR 266*, Appendix IX, Section 2.1.9.) All continuous monitoring devices are to be re-calibrated quarterly in accordance with procedures under Section 60.13(b) of *40 CFR 60.*

The system shall continuously record the measured concentrations, and shall calculate and continuously record the NOx and CO concentrations corrected to a value at 15 percent O_2, dry. The NOx and CO CEMs shall have the capability of recording NOx and CO concentrations during all operating conditions, including startups and shutdowns. Multiple range analyzers or additional "coarse range" analyzers shall be provided as necessary to measure higher concentrations during startup periods. Due to the low concentrations of NOx with appreciable NO_2 expected during operation, chillers or condensers shall not be utilized in the CEMs for measuring NOx concentrations.

A computer data acquisition system which has the capability of interpreting the sampling data; providing a graphical trend analysis; and producing summary reports of the respective 1-hour and 3-hour averages of NOx and CO, and pounds per day and tons per year of NOx, CO, PM_{10}, SOx, and VOC emissions. The summary reports shall also include calculations of cooling tower PM_{10} emissions. [PSD]

Verification: See verification for Condition AQ-27.

AQ-32. As per District Rule 2:1A.b.2., the initial commissioning period shall not exceed more than 60 days (commencing with the first firing of fuel in the power train). The owner/operator shall minimize emissions to the maximum extent possible during the commissioning period. At least 90 days prior to first firing of the facility, the owner/operator shall submit to the APCO and the CEC CPM for their approval an Initial Commissioning Test Plan that will include, but not be limited to the following:

a. A description of the initial commissioning activities that will take place,
b. The duration, in hours, of each initial commissioning activity,
c. A quantification of the criteria pollutant emissions, in either pounds per hour, or pounds per event, and
d. A description of what air emissions limiting equipment will be in place and operating during each initial commissioning activity.

[Non-PSD]

Verification: Not necessary.

AQ-33. Best Available Control Technology for the combustion turbines shall be defined as the following emission control technologies applied to each combustion turbine capable of achieving the emission standards specified in Condition AQ-37 of this permit:

a. Particulate Matter	State-of-the-art combustion turbines, good combustion practices, mist eliminators for lube oil vents, exclusive combustion of natural gas containing no more than 0.4 grain of sulfur per 100 standard cubic feet of natural gas
b. Oxides of Nitrogen	Dry low-NOx combustors, low-NOx duct burners, selective catalytic reduction with ammonia injection
c. Reactive Organic Compounds	Good combustion practices, coincidental VOC reduction by the use of a CO oxidation catalyst
d. Carbon Monoxide	Good combustion practices and use of a CO oxidation catalyst

[PSD]

Verification: See verification for Condition AQ-27.

AQ-34. Best Available Control Technology for the cooling tower shall be defined as the following emission control technologies capable of achieving the emission standards specified in Condition AQ-43 of this permit:

Particulate Matter	Hybrid (wet and dry) cooling tower equipped with 0.0005% drift rate drift eliminators, TDS limit of 5000 mg/liter

Verification: See verification for Condition AQ-27.

AQ-35. The dates and results of all visible emission evaluations required by Condition AQ-37 shall be recorded in a log and maintained for five years for District inspection upon request.

Verification: The project owner shall make the site available for inspection by representatives of the District, the EPA and CEC.

AQ-36. The following opacity limits shall apply at all times:

Emission Point	Opacity Limit
HRSG Exhausts	20% for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor as determined by EPA Method 9
Oil Mist Eliminator Vents	20% for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor as determined by EPA Method 9
Emissions from Any Other Source on Site	40% or Ringlemann 2 for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor

Verification: The project owner shall make the site available for inspection by representatives of the District, the EPA and CEC.

AQ-37. Emissions from each gas turbine, duct burner, and associated HRSG shall meet all of the emission limitations listed in a. through g. below for each power train at any firing rate and ambient conditions (except as noted in Condition AQ-38):

Pollutant	GE	Westinghouse	Either CTG Manufacturer	Verification
Nox as NO_2	18.9[2] pounds per hour	16.8[2] pounds per hour	2.5 ppmvd[2], 1-hr rolling averaging @ 15% O_2	Verified by CEMS and annual compliance test at maximum operating capacity of the turbines[1]
CO	18.5 pounds per hour	16.3 pounds per hour	4 ppmvd, 3-hr rolling averaging @ 15% O_2	Verified by CEMS and annual compliance test at maximum operating capacity of the turbines[1]
Ammonia slip	12.8 pounds per hour	12.8 pounds per hour	5 ppmvd, 3-hour rolling averaging @ 15% O_2	Verified by annual compliance test at maximum operating capacity of the turbines and continuous recording of the injection rate
VOC	5.3 pounds per hour	4.4 pounds per hour	2 ppmvd, 1-hour rolling averaging @ 15% O_2	Verified by annual compliance test at maximum operating capacity of the turbines and VOC/CO algorithms developed from initial source tests
PM_{10} (filterable + condensible)	22.1 pounds per hour	16.4 pounds per hour	0.0012 grain/dscf, 1-hour averaging @ 3% CO_2	Verified by annual compliance test at maximum operating capacity of the turbines and algorithms developed from initial source tests
			<20% for a period	Verified by monthly visible

Pollutant	GE	Westinghouse	Either CTG Manufacturer	Verification
Opacity			aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor as determined by EPA Method 9	emission evaluations and annual compliance test at maximum operating capacity of the turbines
Sox as SO_2	1.24 pounds per hour	1.24 pounds per hour		Verified by fuel sulfur content and fuel use data

Notes: [1]After the first ***five*** annual compliance tests and upon written request to the APCO with adequate justification (consistent demonstration of compliance), the owner/operator may, if allowed by the APCO, use CEM data to verify compliance with the NOx and CO emissions specified above. The owner/operator may also reduce the frequency of testing for VOC and SOx emissions from the HRSG exhaust and the PM_{10} emission testing of the cooling tower after the first ***five*** annual compliance test if consistent demonstration of compliance has occurred and if allowed by the APCO in accordance with District Rule 2:11a.3.(f).

[2] The owner/operator shall install a SCR system that is designed to meet a NOx emission limit of no more than 2.0 ppm, based on a 1-hour rolling average (Demonstration NOx Limit), and guaranteed by the SCR vendor to meet the Demonstration NOx Limit, to the extent that the SCR vendor will provide such a guarantee to the owner/operator. The owner/operator shall install, operate, and maintain the SCR system in a manner designed to achieve the Demonstration NOx Limit, and in conformance with the SCR vendor's installation, operation, and maintenance procedures. For a period of three years commencing with commercial operations, the owner/operator will conduct a demonstration program with District and the CEC CPM oversight to determine whether the owner/operator is able to reliably and continuously operate while maintaining the Demonstration NOx Limit. (The District shall consider allowable excess emissions in accordance with District Rule 3:10 when evaluating the facility's performance with respect to the Demonstration NOx Limit. In addition, the District will consider whether the Demonstration NOx Limit has been achieved on a consistent basis within the allowances under District Rule 3:10 with suitable compliance margin of at least 10% over the entire range of turbine operating conditions, including duct firing, and over the entire range of ambient conditions). Upon conclusion of this three-year demonstration program, if the District determines that the owner/operator can reliably and continuously operate while maintaining the Demonstration NOx Limit, the owner/operator shall accept the Demonstration NOx Limit and correspondingly adjusted hourly mass emission limitations in the facility's Permit to Operate. Should the District and the CEC CPM determine that the owner/operator cannot reliably and continuously operate while maintaining the Demonstration NOx Limit, the NOx emission limit in the facility's Permit to Operate shall remain unchanged. [PSD]

Verification: See Condition AQ-58 and its verification.

AQ-38. The emission limits in Conditions AQ-37 shall not apply during any cold startup (which is not to exceed 4.5 hours in duration), hot startup (which is not to exceed 2.0 hours in duration), warm startup (which is not to exceed 2.5 hours in duration), or shutdown (which is not to exceed 1.0 hour in duration). Selective catalytic reduction (SCR), oxidation catalytic reduction, and good combustion practices shall be used whenever the combustion turbines are operating and to the fullest extent practical during startup and shutdown conditions to minimize pollutant emissions. A stack damper shall be utilized as practical during shutdowns to retain heat in the HRSG in order to minimize startup emissions. Startup shall be defined as the period beginning with ignition and lasting until equipment has reached stable operating mode and has achieved operating permit limits. Cold startup means a startup when the CTG has not been in operation during the preceding 48 hours. Hot startup means a startup when the CTG has been in operation during the preceding 8 hours. Warm startup means a startup that is not a hot or cold startup. Shutdown shall be defined as the period beginning with the lowering of equipment from stable operating load with the intention of full shutdown and lasting until fuel flow is completely off and combustion has ceased.

Verification: See Condition AQ-58 and its verification.

AQ-39. Emissions from each gas turbine, duct burner, and associated HRSG shall meet all of the emission limitations listed below per event for each power train in the various startup or shutdown modes defined in Condition AQ-38:

Pollutant	Cold Startup		Warm Startup		Hot Startup		Shutdown		Verification
	GE	W 501 F	GE	W 501 F	GE	W 501 F	GE	W 501 F	
NOx as NO_2 (pound)	215	140	138	123	75	112	38	38	Verified by CEMS
CO (pound)	750	1105	450	1114	425	847	175	175	
VOC (pound)	80	139	150	138	150	114	128	26	Calculated VOC/CO algorithms developed from initial source tests
PM_{10} (pound)	120	120	70	70	50	50	15	15	Calculated with fuel use and source tests
SOx as SO_2	5.6	5.6	3.1	3.1	2.5	2.5	1.24	1.24	

[PSD]

Verification: See Condition AQ-58 and its verification.

AQ-40. The facility total emissions from gas turbine/HRSG power trains and cooling tower including periods of all equipment startups, shutdowns, and operational modes shall not exceed the following limits during any calendar day:

	GE	Westinghouse	Cooling Tower
PM_{10}	657 pounds per day	503 pounds per day	37.5 pounds per day
NOx as NO_2	679 pounds per day	638 pounds per day	
CO	1832 pounds per day	2603 pounds per day	
SOx as SO_2	30 pounds per day	30 pounds per day	
VOC	258 pounds per day	386 pounds per day	
NH_3	307 pounds per day	307 pounds per day	

[PSD]

Verification: See Condition AQ-58 and its verification.

AQ-41. The facility total emissions from both gas turbine/HRSG power trains, and the cooling tower, including periods of all equipment startups, shutdowns, initial commissioning and operational modes, shall not exceed the following ton per year limits during any consecutive twelve-month period:

	GE (2CTGs)	Westinghouse (2CTGs)	Cooling Tower
PM_{10}	167 tons per year	137 tons per year	7 tons per year
NOx as NO_2	144 tons per year	130 tons per year	
CO	268 tons per year	401 tons per year	
SOx as SO_2	10 tons per year	10 tons per year	
VOC	41 tons per year	65 tons per year	

[PSD]

Verification: See Condition AQ-58 and its verification.

AQ-42. The maximum total dissolved solids (TDS) of the cooling tower blowdown water shall not exceed 5000 mg/liter. The owner/operator shall sample and record the TDS content of the cooling tower blowdown water on a weekly basis or at a frequency consistent with that set by the Regional Water Quality Control Board if more stringent. The owner/operator shall maintain a log containing the date, the results of each test, and calculations of the mass emission rate of particulate matter from the cooling tower. [PSD]

Verification: See Condition AQ-58 and its verification.

AQ-43. The PM_{10} emission rate for the cooling tower shall not exceed 37.5 pounds per day at a maximum circulation rate not to exceed 125,000 gallons per minute using the following method to determine compliance:

(gallons of drift/minute) x (1 minute/60 seconds) x (3.785 liters/gallon) x (mg PM_{10}/liter) x (1 gram/1000milligrams) = grams PM_{10}/second

(grams PM_{10}/second) x (60 seconds/minute) x (60 minutes/hour) x (1 pound/454 grams) = pounds PM_{10}/hour

(pounds PM_{10}/hour) x (24 hours/day) = pounds PM_{10}/day
[PSD]

Verification: See Condition AQ-58 and its verification.

AQ-44. Cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high efficiency mist eliminators with a minimum guaranteed drift rate of 0.0005%. The owner/operator shall provide drift eliminator vendor's justification and guarantee of the drift rate at least thirty (30) days prior to commencement of construction. [PSD]

Verification: See verification for Condition AQ-27.

AQ-45. A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure is to be kept on-site and be available to the District for review and approval. [PSD]

Verification: See verification for Condition AQ-27.

AQ-46. No compounds containing hexavalent chromium shall be added to cooling tower's circulating water. The following information shall be provided to the District in writing at least ninety (90) days before the tower is operated:

a. Owner/operator of the tower;
b. Location of the tower;
c. Cooling tower type and materials of construction;
d. A description of the cooling water treatment program chosen, as well as the circulating water monitoring plan.

[Non-PSD]

Verification: See verification for Condition AQ-27.

AQ-47. Emission testing for NO2, CO, PM_{10}, VOC, and SO_2 emissions from each HRSG exhaust and emission calculations of the PM_{10} emissions from the cooling tower shall be conducted annually by an independent testing firm(s) in strict compliance with the test methods specified in Condition AQ-50 and the calculation method specified in Condition AQ-43. The cooling tower emission calculations shall be conducted by a licensed Cooling Tower Institute testing firm and shall include an evaluation of the operating efficiency of the drift eliminators in at least two cells. The Air Pollution Control Officer and the CEC CPM may approve the use of the NOx and CO CEMs readings to quantify annual emissions in lieu of emission testing after the first ***five*** annual compliance test as provided by Condition AQ-37 if annual relative accuracy procedures, ***consistent with the EPA Quality Assurance Guidelines***, are completed as required by Condition AQ-31 above. Results of all emission testing shall be forwarded to the District and the CEC CPM for compliance verification. An emission testing protocol detailing the methods of sampling and analysis shall be submitted to the District for approval 30 days prior to the initial testing and any subsequent test required under the above rule, and the District shall be notified at least ten (10) days prior to the actual date of testing so that a District observer can be present. The following parameters shall also be determined during the emission testing:

a. Natural gas consumption SCFH
b. Electricity generated during the test
c. Ammonia injected: lb/scf of natural gas burned; lb/hr
d. Stack exhaust flow rate in dry standard cubic feet per minute
e. Exhaust gas oxygen concentration, in percent
f. Exhaust gas temperature in degrees Fahrenheit
g. Exhaust gas moisture content
h. ***CO/VOC surrogate ratio***.

[PSD]

<u>Verification:</u> Forty five (45) days after testing, the project owner shall provide the District and the CEC CPM a copy of the source test results. All exemption from annual testing shall be requested in writing to the CEC CPM.

AQ-48. Emission testing of NOx, CO, VOC, SO_2, and PM_{10} during periods of cold startup, warm startup, hot startup, and shutdown for each HRSG exhaust shall be conducted at least once every five years commencing with the initial compliance test.

<u>Verification:</u> Fourty five (45) days after testings, the project owner shall provide the District and the CEC CPM a copy of the source test results.

AQ-49. At least four sampling ports must be provided on each HRSG exhaust stack (located on the same horizontal plane, 90 degrees apart, and at least two [2] duct diameters downstream, and one-half [½] duct diameters upstream of any flow disturbance) and shall consist of 4-inch female NPT couplings welded to the stack. The couplings shall be supplied with 4-inch pipe plugs. Sampling platforms shall be installed on each stack. The location of the sampling ports and design of the platform must be approved by the District prior to installation.

Verification: See verification for Condition AQ-27.

AQ-50. The following test methods shall apply when testing for the specific pollutant is required unless EPA- approved alternative test methods have been authorized by the District:

Particulate Matter	CARB Method 5 (front and back half analysis)
Oxides of Nitrogen	EPA Method 20
Carbon Monoxide	EPA Method 10 or ARB Method 100
Sulfur dioxide	EPA Method 20
Reactive Organic Compounds	EPA Method 18
Ammonia	Bay Area AQMD Method ST-1B
Stack Gas Oxygen	EPA Method 20

[PSD]

Verification: Not necessary.

AQ-51. Within 60 days after startup, emission testing of each HRSG exhaust in accordance with methods specified in Condition AQ-50 shall be performed to determine the mass emission rates and concentrations of NOx, CO, VOC, SO_2, and PM_{10} at 100 percent gas turbine load and ambient conditions and under the various startup and shutdown modes defined above in Condition AQ-37. The test results shall be corrected to ISO standard ambient conditions.

In addition, the initial compliance test shall include emission testing for the following chemical compounds using the specified testing methods for purposes of satisfying Condition 9:

a. benzene — CARB Method 410
b. formaldehyde — CARB Method 430
c. acrolein — (Note: The test method for this compound is currently under investigation by CARB and should be verified with the CARB Monitoring & Laboratory Division)

[Non-PSD]

Verification: Fourty five (45) days after testings, the project owner shall provide the District and the CEC CPM a copy of the source test results.

AQ-52. The SCR system shall include provisions for continuously monitoring and recording the amount of ammonia injected in pounds per hour, the SCR catalyst inlet temperature, pressure differential across the SCR catalyst, and be equipped with a control module that continuously adjusts the NH3 injection rate to achieve the desired NOx emission level. [PSD]

Verification: See verification for Condition AQ-27.

AQ-53. Within 60 days after initial startup and annually thereafter within thirty (30) days prior to the renewal date of the Permit to Operate, the owner/operator shall conduct District-approved emission testing on each HRSG exhaust to determine compliance with the ammonia slip emission limit of Condition AQ-37. The test shall be in accordance with Bay Area AQMD Method ST-1B. The emission test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, SCR system ammonia injection rate, and the corresponding ammonia emission concentration at the HRSG exhaust. The test shall be conducted over the expected operating range of the turbine. Continuing compliance with the ammonia slip emission limit of Condition AQ-37 shall be demonstrated daily through calculations of corrected ammonia concentrations based upon the source test heat input correlation and continuous records of ammonia injection rates. [PSD]

Verification: Fourty five (45) days after testings, the project owner shall provide the District and the CEC CPM a copy of the source test results.

AQ-54. The selective catalytic reduction (SCR) system shall be activated and ammonia shall be injected whenever the SCR has reached or exceeded 500^{o}F except for periods of equipment malfunction. Except during periods of startup, shutdown, and malfunction, ammonia slip shall not exceed 5 ppmvd at 15% O_2. [PSD]

Verification: See Condition AQ-58 and its verification.

AQ-55. To demonstrate compliance with the mass emission limitations for NOx, CO, PM10, SOx, VOC, and NH 3 stated in conditions stated in Conditions AQ-37, 39, 40, and 41 above, the owner/operator shall calculate and record the hourly, daily, and year-to-date mass emissions (including initial commissioning and startup and shutdown emissions) from each power train using CEM emission data (for NOx and CO) and emission factors derived from the most recent annual emission test (for PM10, VOC, NH3 and SOX). The owner/operator shall use the actual heat input rates, actual gas turbine startup times, actual gas turbine shutdown times, and CEC and District-approved emission factors developed during the emission testing required by Conditions AQ- 48, 50 and 51 to calculate these emissions.

The daily emissions from the cooling tower shall be calculated using the method specified in Condition AQ-43. [PSD]

Verification: See Condition AQ-58 and its verification.

AQ-56. The duct burners shall not be operated unless the associated combustion gas turbines, oxidation catalyst, and SCR system is in operation.

Verification: See Condition AQ-58 and its verification.

AQ-57. Exhaust stack heights of the HRSG's shall not exceed 150 feet above grade level at the stack base.

Verification: See verification for Condition AQ-27.

AQ-58. Monthly emission reports shall be required to be submitted by the 15th of the month following data recording and shall include:

a. all periods 3 minutes and longer in duration when opacity from either HRSG exhaust stack or any oil mist eliminator exceeds the specified limits and the reason for the excursion;
b. all periods when NOx, CO, VOC, PM_{10}, SOx, or NH_3 emission from the exhaust stacks exceed the specified limits and the reason for the excursion;
c. all periods the NOx, or CO CEMs for the HRSGs exhaust were not functioning and the reasons for the same;
d. documentation of the quarterly calibrations of the monitoring devices required in Condition AQ-31 and a report of corrective maintenance required as a result of the calibrations;
e. documentation of daily and monthly emissions of PM10, NOx, CO, SOx, and VOC from the HRSG exhausts and the cooling tower using the methods specified in Conditions AQ-43 and 55;
f. documentation of monthly natural gas fuel consumption for the gas turbines and duct burners;
g. documentation of fuel sulfur content through monthly reports from natural gas supplier;
h. documentation of the date and times when the temperature in the SCR is less than 500^{o}F or less than the design temperature of the catalyst;
i. documentation of total operation time, date and time at the beginning and end of each startup/shutdown period, hours in cold startup, hours in warm startup, hours in hot startup, and hours in shutdown periods for each power train;
j. documentation of quantity of electricity generated on a daily basis and total for the month;
k. documentation of corrective action taken to correct each event of malfunctioning operating or emission control equipment or any condition causing excessive emissions;
l. if no permit limitations were exceeded, the report must so state.

[PSD]

Verification: The project owner shall submit to the District the above information for the preceding calendar month by the 15 of the following month. This information shall be maintained on site for a minimum of five (5) years and shall be provided to District, EPA and CEC personnel on request.

AQ-59. Drawings and design details of the continuous emission monitoring equipment, data acquisition systems, SCR system, and oxidation catalyst shall be submitted to the District for approval prior to purchasing such equipment. [PSD]

Verification: See verification for Condition AQ-27.

AQ-60. Fugitive dust emissions from unpaved roads or any other area without vegetative cover shall be controlled at all times such that a violation of an ambient air standard or a public nuisance is not created at any point beyond the plant property line. [PSD]

Verification: See verification for Condition AQ-28.

AQ-61. Solid wastes from the softener filter press and the crystallizer filter press shall be removed from the site continuously or stored in containers having a cover. All solid wastes from the subject presses shall be transported offsite in a wet condition in covered containers at all times unless transported in dry form in a totally sealed container. It shall be the responsibility of the facility owner/operator to insure that any and all contracts or company carriers adhere to this condition. [Non-PSD]

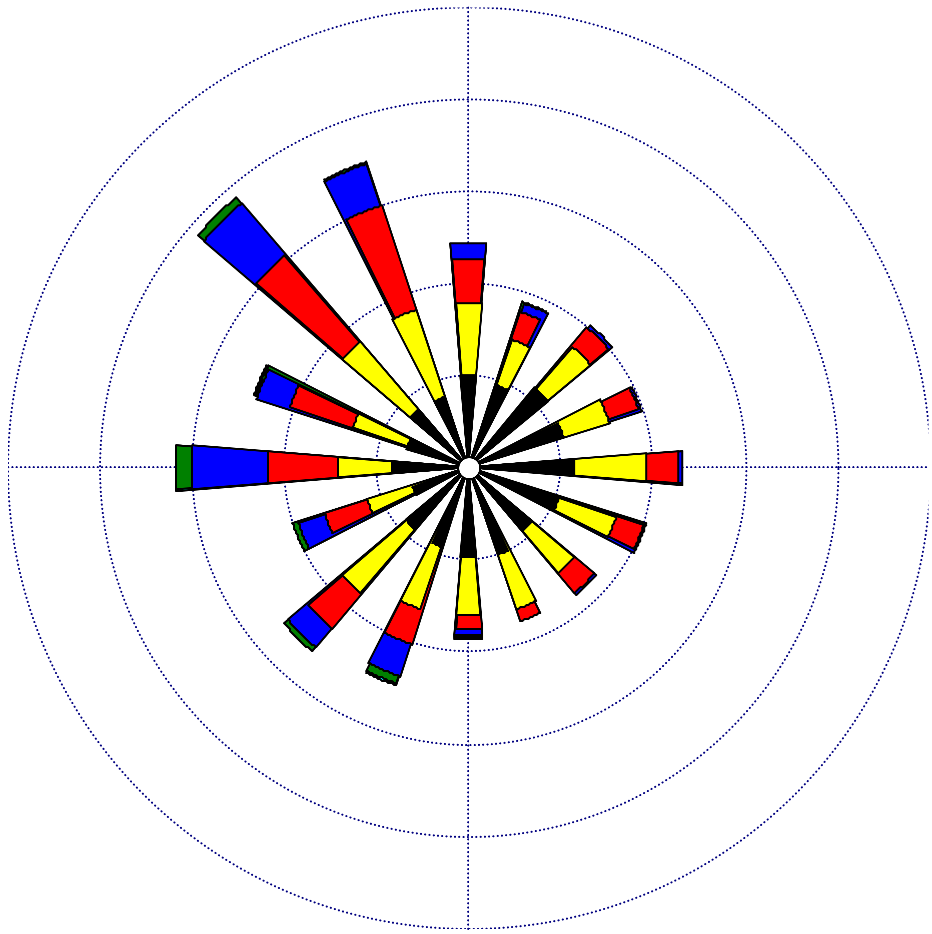
Verification: Not necessary.

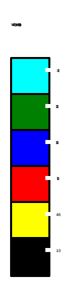
APPENDIX A

Wind Rose Pattern

WIND ROSE PLOT

Station #24257 - BRUSH MOUNTAIN - 1997 ANNUAL WIND ROSE



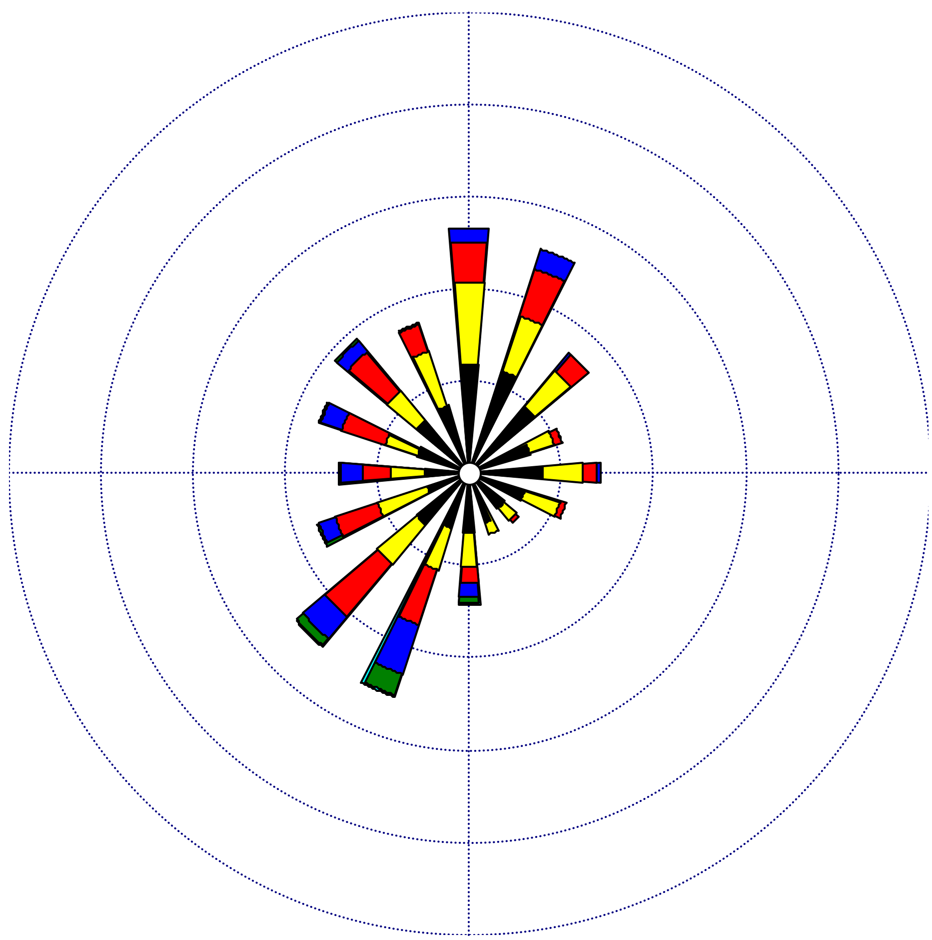


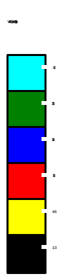
MODELER	DATE	COMPANY NAME
	10/19/00	
DISPLAY	UNIT	COMMENTS
Wind Speed	**Knots**	
AVG. WIND SPEED	CALM WINDS	
5.85 Knots	**23.64%**	
ORIENTATION	PLOT YEAR-DATE-TIME	PROJECT/PLOT NO.
Direction (blowing from)	**1997 Jan 1 - Dec 31 Midnight - 11 PM**	**ANNUAL WIND ROSE**

WRPLOT View 3.15 by Lakes Environmental Software - www.lakes-environmental.com

WIND ROSE PLOT

Station #24257 - BRUSH MOUNTAIN - 1997 FIRST QUARTER WIND ROSE



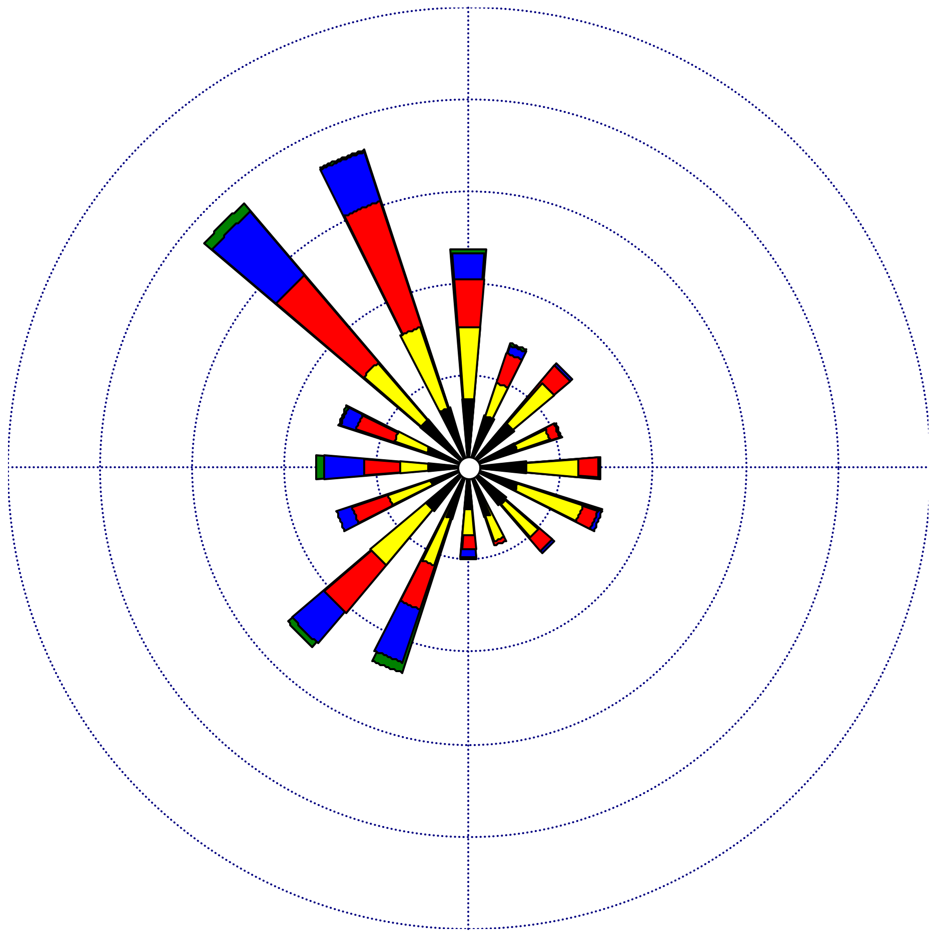


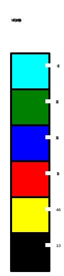
MODELER	DATE **10/19/00**	COMPANY NAME
DISPLAY **Wind Speed**	UNIT **Knots**	COMMENTS
AVG. WIND SPEED **5.66 Knots**	CALM WINDS **46.25%**	
ORIENTATION **Direction (blowing from)**	PLOT YEAR-DATE-TIME **1997** **Jan 1 - Mar 31** **Midnight - 11 PM**	PROJECT/PLOT NO. **FIRST QUARTER WIND ROSE**

WRPLOT View 3.15 by Lakes Environmental Software - www.lakes-environmental.com

WIND ROSE PLOT

Station #24257 - BRUSH MOUNTAIN - 1997 SECOND QUARTER WIND ROSE



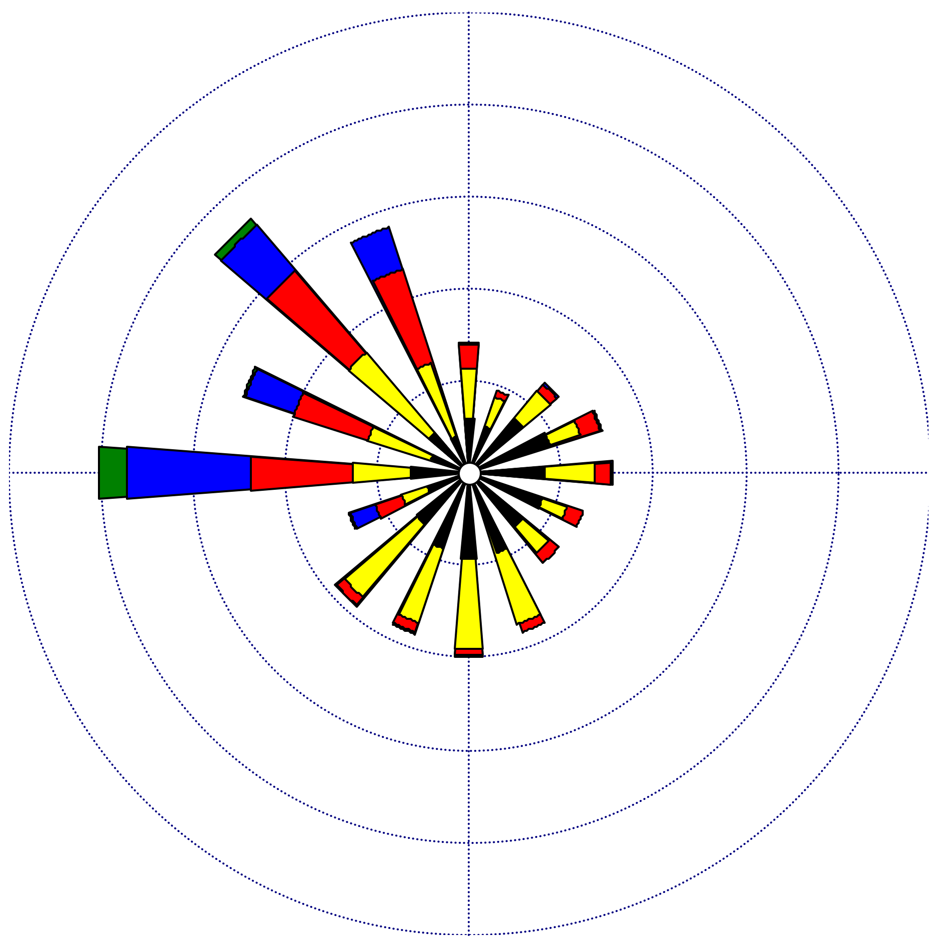


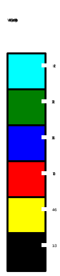
MODELER	DATE **10/19/00**	COMPANY NAME
DISPLAY **Wind Speed**	UNIT **Knots**	COMMENTS
AVG. WIND SPEED **6.44 Knots**	CALM WINDS **12.11%**	
ORIENTATION **Direction (blowing from)**	PLOT YEAR-DATE-TIME **1997** **Apr 1 - Jun 30** **Midnight - 11 PM**	PROJECT/PLOT NO. **SECOND QUARTER WIND ROSE**

WRPLOT View 3.15 by Lakes Environmental Software - www.lakes-environmental.com

WIND ROSE PLOT

Station #24257 - BRUSH MOUNTAIN - 1997 THIRD QUARTER WIND ROSE



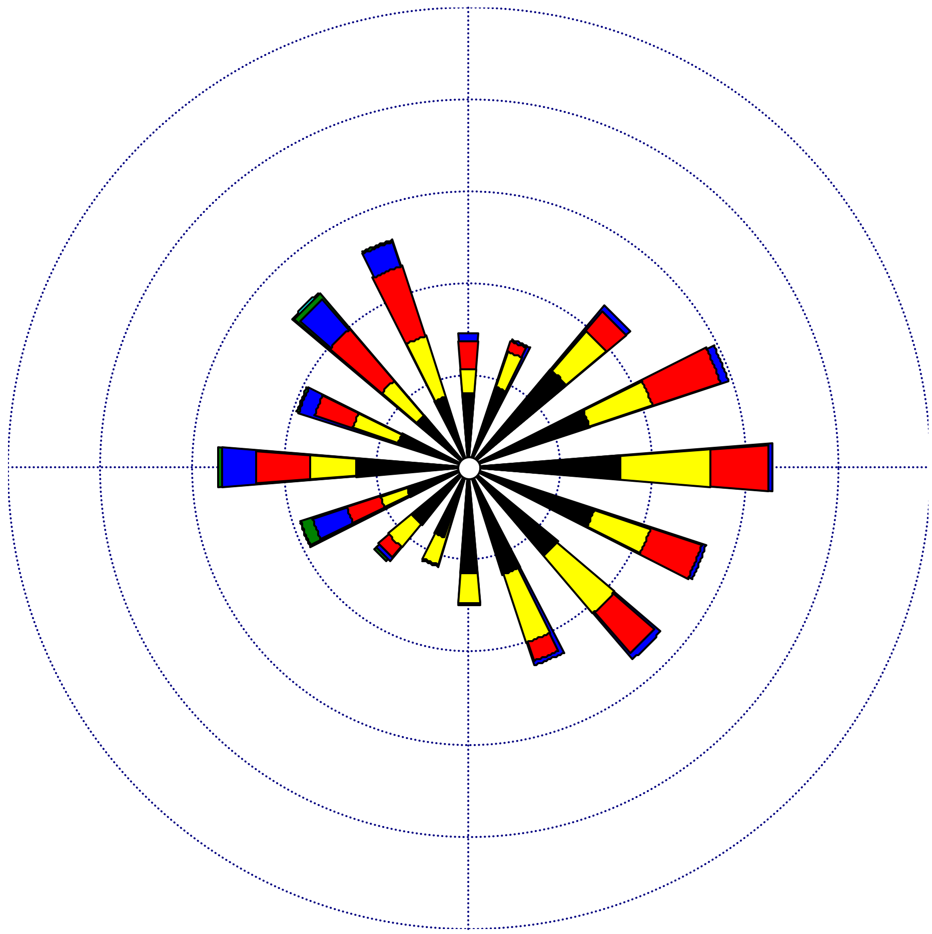


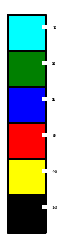
MODELER	DATE	COMPANY NAME
	10/19/00	
DISPLAY **Wind Speed**	UNIT **Knots**	COMMENTS
AVG. WIND SPEED **5.94 Knots**	CALM WINDS **6.34%**	
ORIENTATION **Direction (blowing from)**	PLOT YEAR-DATE-TIME **1997** **Jul 1 - Sep 30** **Midnight - 11 PM**	PROJECT/PLOT NO. **THIRD QUARTER WIND ROSE**

WRPLOT View 3.15 by Lakes Environmental Software - www.lakes-environmental.com

WIND ROSE PLOT

Station #24257 - BRUSH MOUNTAIN - 1997 FOURTH QUARTER WIND ROSE





MODELER	DATE **10/19/00**	COMPANY NAME
DISPLAY **Wind Speed**	UNIT **Knots**	COMMENTS
AVG. WIND SPEED **5.14 Knots**	CALM WINDS **30.24%**	
ORIENTATION **Direction (blowing from)**	PLOT YEAR-DATE-TIME **1997 Oct 1 - Dec 31 Midnight - 11 PM**	PROJECT/PLOT NO. **FOURTH QUARTER WIND ROSE**

WRPLOT View 3.15 by Lakes Environmental Software - www.lakes-environmental.com

APPENDIX B

PROPOSED VOLUNTARY WOOD STOVE REPLACEMENT PROGRAM

THE PROJECT

Three Mountain Power Project (TMPP) is a nominal 500 megawatt natural gas-fired, combined-cycle power plant comprised combustion turbines, one steam turbine, and supporting equipment. TMPP is expected to emit 167 tons per year of particulate matter (PM10), which could create significant adverse impacts. Staff is investigating all feasible means of reducing any impacts to a level of insignificance.

THE PROBLEM

The Burney area experiences numerous violations of the state PM10 ambient air quality standards. From 1989 through 1993 the data show that PM10 violations occurred primarily between the months of November through March when the weather is cold. The Burney area experiences a low inversion layer during these cold months. This low inversion layer traps the air pollutants causing them to accumulate, which in turn contributes to the violations of the PM10 air quality standard.

To mitigate the project's PM10 emission impacts, staff recommends that the applicant implement a combination of road paving and retrofitting of residential wood burning devices used in the Burney area. This paper outlines the main concepts of the voluntary wood stove replacement program.

HOW THE PROGRAM WORKS:

Basically, the new wood stoves, called "EPA Phase II Certified Units", burn much cleanlier and efficiently than older units that are not EPA certified. Thus, replacing the older units with the new units will result in both lower emissions and a reduction in the amount of wood being burned. These emission reductions will mitigate part of the project's PM10 and volatile organic compound (VOC) emissions.

THE PROGRAM:

Staff suggests that the applicant designs and markets a program, which would achieve the following goals:

- ***The program will last for three years or until the available funds (approximately $600,000.00) are exhausted, or 455 units have been installed, whichever comes first.***
- ***Any funds remaining will be used for road paving as designated by the California Energy Commission in consultation with the Shasta Air Quality Management District, or for other measures as agreed to by those parties and TMPP.***

- ***The program is strictly on a voluntary basis to willing residents of Burney and Johnson Park.***
- ***Each resident participating in the program will be eligible to receive an EPA Phase II Certified wood stove unit installed, free of charge or up to a total of $1,225.00 cost toward a more expansive model, whichever is less.***
- ***Priority will be given to retailers and licensed installers who have businesses in the Burney area to sell and install the new wood stoves, and remove the old wood stoves.***
- ***Each resident participating in the program would only do business with the retailer and the professional, licensed installer.***
- ***The retailer must certify that he or she has rendered all old wood stoves replaced non-operative by permanent removal of the stove doors.***
- ***The retailers are required to keep records of old wood stove units being removed and installation of the new units, and submit those records to TMPP on a weekly basis for reimbursement.***

HOW STAFF ARRIVED AT THE 455 UNITS

Criteria: To achieve a total of 179 TPY PM10 (including 10TPY of S0x) offsets. These offsets will be broken down to 134 TPY to be provided with road paving for the three dry calendar quarters, and 45 TPY will be provided by the installation of new wood stoves for one wet calendar quarter.

Known data (reference EPA AP-42, Table 1.10-1):

1. conventional wood stove = 30.6 lb PM10/ton, and 53 lb VOC/ton
2. non-catalytic wood stove phase II certified = 14.6 lb PM10/ton, and 12 lb VOC/ton
3. burn 8 cords/year each (information taken from local residents at workshops)
4. each cord = 1400 kg

Calculations:

- Convert from cord to tonnage of wood:

$$\frac{8 cords}{yr} * \frac{1400 kg}{cord} * \frac{2.205 lb}{kg} * \frac{ton}{2000 lb} = 12.35 \frac{tons}{yr}$$

- Emissions reduction per wood stove conversion:

$$\Delta \dot{E} = \left(\frac{30.6 lbPM_{10}}{ton} - \frac{14.6 lbPM_{10}}{ton}\right) * \frac{12.35 ton}{yr} = \frac{197.6 lbPM_{10}}{unit * yr}$$

- Numbers of unit needed:

$$\frac{45ton}{yr} * \frac{2000lb}{ton} * \frac{unit}{197lbPM_{10}} = 455units$$

- Cost:

@ low \$900/unit =\$410,000
@ high \$1500/unit = \$685,000

- VOC emission reduction for 455 units conversion:

$$\Delta \dot{E} = (\frac{53lb}{ton} - \frac{12lb}{ton}) * 455units * \frac{12.35ton}{yr} = 230,400lb = 115tons$$

$$\Delta \dot{E} = 115tons \text{ VOC}$$

REFERENCES

ARB (Air Resource Board). 1987-1998. California Air Quality Data, Annual and Quarterly Summaries.

ARB (Air Resource Board). 1989. A Proposed Suggested Control Measure for the Control of Emissions from Residential Wood Combustion.

TMPP (Three Mountain Power, Llc) 1999. Application for Certification, Three Mountain Power Project (99-AFC-2). Submitted to the California Energy Commission, March 14, 1999.

TMPP (Three Mountain Power, Llc) 2000 a.

TMPP (Three Mountain Power, Llc) 2000 b. Letter to Mr. Michael Kussow Outlining A Proposal to Provide Offsets for PM10 and VOC, Three Mountain Power Project (99-AFC-2). Submitted to Shasta County AQMD, May 8, 2000.

TMPP (Three Mountain Power, Llc) 2000 c. Joint statement of Three Mountain Power, LLC and the California Unions for Reliable Energy (CURE) July 2000.

SCAQMD (Shasta County Air Quality Management District) 2000. Final Determination of Compliance, October 10, 2000.

POWER PLANT EFFICIENCY

Supplemental Testimony of Steve Baker

INTRODUCTION

In response to concerns regarding water consumption, the applicant proposes to modify the Three Mountain Power Project (TMPP) by substituting a hybrid wet-dry cooling system for the evaporative (wet) cooling system originally proposed. In addition, the existing Burney Mountain Power Project, a 10 MW biomass-fired power plant with an evaporative cooling system located adjacent to the TMPP, will be converted to use the same hybrid cooling system.

ANALYSIS

ALTERNATIVES TO REDUCE WASTEFUL, INEFFICIENT AND UNNECESSARY ENERGY CONSUMPTION

PROJECT CONFIGURATION

A dry cooling system, such as the one employed on the Sutter Power Plant Project (97-AFC-2) and the one proposed for the Otay Mesa Generating Project (99-AFC-5) can reduce both maximum power output and fuel efficiency on hot days; the benefit is a significant savings in water consumption. A wet cooling system more effectively cools the steam turbine's condenser in hot weather, permitting higher efficiency and greater power output, but at the expense of significantly greater water consumption.

The hybrid system proposed in the Mitigation Plan (TMP 2000a), however, yields many of the benefits of both wet and dry systems, while minimizing the drawbacks of both. When ambient temperature is low enough, the dry cooling system cools the condenser, consuming no water. As temperatures rise, the wet cooling tower is phased in, a cell at a time, to assist in cooling. Only in the hottest conditions will the wet cooling system, with its significant water consumption, be run at full load. The result is maximum power output and fuel efficiency nearly equal to those to be had with only a wet cooling system.

The applicant proposes to size the dry portion of the cooling system to carry 100 percent of the load at 48°F, a typical day, and to size the wet portion of the system to carry 100 percent of the load at 98°F, a hot day (TMP 2000a, p. 2-29). The project output and efficiency under the Mitigation Plan (TMP 2000a, Appendix E) compare with the original proposal (TMP 1999a, AFC, Table 2.1-1) thus:

TMPP Power Output and Fuel Efficiency
Wet versus Hybrid Cooling Systems[1]

	Original Proposal		Mitigation Plan	
Ambient Temperature	48°F	108°F	48°F	108°F
Maximum Power Output (MW)	528	498	525	497
Fuel Efficiency (LHV)	52.2 %	51.6 %	53.4 %	53.8 %

[1] General Electric Frame 7FA Gas Turbine

The effect of substitution of the hybrid cooling system on project power output will be practically nil; the reduction of project fuel efficiency will be so small as to be insignificant.

CONCLUSION

Incorporation of a hybrid wet-dry cooling system into the TMPP will result in insignificant adverse impacts on project power output and fuel efficiency.

REFERENCES

TMP (Three Mountain Power, LLC). 1999 a. Application for Certification, Three Mountain Power Project (99-AFC-2). Submitted to the California Energy Commission, March 3, 1999.

TMP (Three Mountain Power, LLC). 2000a. Detailed Mitigation Plan and Analysis of Impact Assessments In Resource Areas Affected by the Mitigation Plan. Submitted to the California Energy Commission, August 21, 2000.

LAND USE
Testimony of Gary D. Walker

Based on new information, staff hereby supplements its land use testimony regarding the potential for the Three Mountain Power Project to reduce the amount of groundwater flowing over Burney Falls, an issue raised by the California Department of Parks and Recreation (CDPR). Staff and CDPR were concerned that the reduction in flow could significantly affect the recreational land use of the McArthur-Burney Falls Memorial State Park. Since staff's testimony was filed, the applicant has made a mitigation proposal to reduce the project's water use (TMPP 2000). The applicant and CDPR have entered into a mitigation and settlement agreement that incorporates that proposal and includes additional measures (Lockyer 2000). The agreement states that it resolves all of CDPR's concerns regarding the project's potential impacts on Burney Falls. Staff has also received additional information regarding the effect of the project on groundwater, and concludes that the project with the mitigation proposal would not substantially reduce the flow of water over Burney Falls (Bond 2000). Therefore, the project would not have a significant adverse land use impact on McArthur-Burney Falls Memorial State Park.

REFERENCES

Bond, Linda. 2000. Consultant to California Energy Commission staff. Telephone conference with California Energy Commission Staff, including Gary D. Walker. November 2, 2000.

Lockyer, Bill 2000. California Attorney General. Mitigation and Settlement Agreement Between Three Mountain Power, LCC and California Department of Parks and Recreation. August 18, 2000. Submitted to the CEC on August 22, 2000.

TMPP (Three Mountain Power Project) 2000. Detailed Mitigation Plan and Analysis of Impact Assessments in Resource Areas Affected by the Mitigation Plan. Submitted to the California Energy Commission on August 21, 2000.

NOISE

Testimony of Kisabuli

INTRODUCTION

The construction and operation of any power plant creates noise, or unwanted sound. The character and loudness of this noise, the times of day or night during which it is produced, and the proximity of the facility to sensitive receptors combine to determine whether a proposed project will meet applicable noise control laws and ordinances, and whether it will create significant adverse environmental impacts.

The purpose of this analysis is to identify the likely noise impacts from the Three Mountain Power Project (TMPP) and to recommend conditions to ensure that the project will comply with all applicable laws, ordinances, regulations and standards, and that any noise impacts are not significant.

Before certifying the TMPP, the Energy Commission must find that the project:

1. will likely be built and operated in compliance with all applicable noise laws, ordinances, regulations and standards; and
2. will present no significant adverse noise impacts.

For a description of the terms used to describe noise and methods to measure and evaluate noise, please see **"NOISE: Appendix A"**.

This analysis is based, in part, on information provided in the Application for Certification (AFC) (TMPP 1999a), Supplemental Filings (TMPP 1999b), site visits, workshops, staff data requests and applicant responses (TMPP 1999c - h), and discussions with other agency representatives.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

Under the Occupational Safety and Health Act of 1970 (29 USC § 651 et seq.), the Department of Labor, Occupational Safety and Health Administration (OSHA) has adopted regulations (29 CFR § 1910.95) that establish maximum noise levels to which workers at a facility may be exposed. These OSHA noise regulations are designed to protect workers against the effects of noise exposure, and list permissible noise level exposure as a function of the amount of time during which the worker is exposed. (Please see **Noise: Appendix A, Table A4** immediately following this section.) OSHA regulations also dictate hearing conservation program requirements and workplace noise monitoring requirements. The administering agency for the above authority is the Federal Occupational Safety and Health Administration (Fed-OSHA).

Noise Control Act of 1972 (42 USC § 4901 et seq.; 40 CFR Parts 201-211) sets performance standards for noise emissions from "major sources." The Environmental Protection Agency (EPA) has identified a day/night level (Ldn) of 55 dBA[1] as providing reasonable protection against community annoyance and activity interference due to noise. EPA administers the Noise Control Act.

STATE

There are no state regulations governing off-site (community) noise. Rather, state planning law (Gov. Code, § 65302) requires that all counties and cities prepare and adopt a General Plan. Government Code section 65302(f) requires that a noise element be prepared as part of the General Plan. This element is to "address existing and foreseeable noise problems…." Other state laws, ordinances, regulations and standards (LORS) include the California Environmental Quality Act (CEQA) and the California Occupational Safety and Health Act (Cal-OSHA).

California Vehicle Code, sections 23130 and 23130.5, sets noise limits for highway vehicles. The California Highway Patrol and the Shasta County Sheriff's Office administer the vehicle code.

CAL-OSHA

California Occupational Safety and Health Administration (Cal-OSHA) has promulgated Occupational Noise Exposure Regulations that set employee noise exposure limits.

Cal-OSHA regulations (Cal. Code Regs., tit. 8, § 5095 et seq.) are the same as the federal OSHA criteria described above. The criteria are based on a worker's noise level exposure over a specific time period. Maximum permissible worker noise exposure levels to protect against damage to the workers' hearing have been established. The administering agency is Cal-OSHA.

CEQA

CEQA requires that significant environmental impacts be identified, and that such impacts be eliminated or mitigated to the extent feasible. The applicable CEQA Guidelines (Cal. Code Regs., tit. 14, §15000 et seq., Appendix G § XI) explain that a significant effect from noise may exist if a project would result in:

1. Exposure of persons to, or generation of, noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies.
2. Exposure of persons to, or generation of, excessive ground borne vibration or ground borne noise levels.
3. A substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project.
4. A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project.

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[1] Please see **Noise: Appendix A,** immediately following this section, for the definition of dBA and other terms used throughout this report.

LOCAL

SHASTA COUNTY GENERAL PLAN - NOISE ELEMENT

The Shasta County General Plan 1998 contains a Noise Element that establishes environmental noise limits based on the land use of the property receiving the noise. The permissible noise levels are outlined below in **NOISE: Table 1**. The administering agency for the above authority is the Shasta County Department of Planning and Development Services.

SETTING

The site is located directly west of State Route 299, approximately one-mile northeast of Burney and one-half mile southwest of Johnson Park in Shasta County, California. The site is bounded by forested open space to the north and south, opens space and State Route 299 to the east, and the McCloud River Railway to the west. The site is generally level, located at approximately 3,140 feet above mean sea level (MSL).

The nearest sensitive receptor is a single-family residence located approximately 1,400 feet due west of the property boundary, on Black Ranch Road. Several residences in the southern limits of Johnson Park are located approximately 1,800 feet northwest of the property boundary. The nearest schools to the site include an elementary and junior/senior high school in the town of Burney. These schools are located approximately 1.5 miles south of the property. The majority of the lands surrounding the site consist of natural open space. Direct access to the site is provided via State Route 299.

There are sensitive receptors (schools, residences and places of worship) within a 2-mile radius of the powerplant site. This is identified by staff as an area inside which construction and operation of a powerplant project is likely to cause noise impacts. Since sensitive receptors are within a 2-mile radius, mitigation measures are likely to be required to minimize noise impacts to these sensitive receptors.

For additional information regarding the site, setting and other project features, please see the Project Description section.

NOISE: Table 1
Shasta County General Plan-Noise Element

Table N-1 Noise level performance standard for new projects Affected by or including non-transportation sources.			
Noise Level Descriptor		Daytime (7 a.m. to 10 p.m.)	Nighttime (10 p.m. to 7 a.m.)
Hourly L_{eq}, dBA		55	50
The noise levels specified above shall be lowered by five (5) dBA for simple tone noises, noises consisting primarily of speech or music, or for recurring impulsive noises. These noise level standards do not apply to residential units established in conjunction with industrial or commercial uses (e.g., caretaker dwellings). The County can impose noise level standards, which are more restrictive than those specified above based upon determination of existing low ambient noise levels. In rural areas where large lots exist, the exterior noise level standard shall be applied at a point 100 feet away from the residence.			
	HVAC Systems Pump Stations Emergency Generators/Boilers Steam Valves Generators Air Compressors Conveyor Systems Pile Drivers Drill Rigs Welders Outdoor Speakers	Cooling Towers/Evaporative Condensers Lift Stations Steam Turbines Fans Heavy Equipment Transformers Grinders Gas or Diesel Motors Cutting Equipment Blowers	
The types of uses which may typically produce the noise sources described above include but are not limited to: industrial facilities including lumber mills, trucking, tire shops, auto maintenance shops, metal fabricating shops, shopping centers, drive-up windows, car washes, loading docks, public works projects, batch plants, bottling and canning plants, recycling centers, electric generating stations, race tracks, landfill, sand and gravel operations, and athletic fields. Note: For the purposes of the Noise Element, transportation noise sources are defined as traffic on public railroads, railroad lines and aircraft in flight. Federal and State regulations preempt control of the noise from these sources. Other noise sources are presumed to be subject to local regulations, such as a noise control ordinance. Non-transportation noise sources may include industrial operations, outdoors recreational facilities, HVAC units, loading docks etc.			

Source: 1998 Shasta County General Plan - Noise Element.

AMBIENT NOISE SURVEY

The Energy Commission's power plant certification regulations require that noise measurements be made at noise-sensitive locations where there is a potential for an increase of 5 dBA or more over existing background noise levels during construction or operation of a proposed power plant.

The applicant performed noise measurements between November 6 and November 8, 1998. Data was collected for approximately 48 hours at each of the three locations and additional spot sampling was performed at five other locations. All sound measurement equipment was calibrated before and after completion of the noise measurement. Results of the 48-hour sound level monitoring are shown on

(**NOISE:** Table 2) and results of the spot sound level monitoring are shown on (**NOISE:** Table 3) below.

NOISE: Table 2
48-Hour Average Ambient Sound Levels

48-Hour Average Sound Level Descriptors (dBA)								
Site	L_{eq}	L_{max}	L_{min}	L_{10}	L_{50}	L_{90}	L_{dn}	CNEL
ML 1	58.2	76.3	40.3	63.5	52.5	43.0	60.3	60.6
ML 2	59.5	83.9	41.0	60.7	47.6	42.8	64.2	64.4
ML 3	63.2	94.8	43.2	64.2	52.9	47.7	64.2	64.3

Monitoring Locations: ML 1: Southeastern corner of the Burney Mountain Power facility at State Route 299 E and Energy Drive. ML 2: Front yard area of the Hathaway residence located at 21305 Black Ranch Road. ML 3: Southwestern corner of the California Department of Forestry Fire Station located at 37966 State Route 299. (Source: TMP 1999a, AFC § 6.4.2.2 and Table 6.4-4).

NOISE: Table 3
Intermittent Ambient Sound Levels

Site	Start Time	L_{eq}	L_{max}	L_{min}	L_{10}	L_{50}	L_{90}
ML 1	8:00 a.m.	61.3	73.5	45.0	62.5	52.5	49.0
ML 2	9:30 a.m.	60.8	74.0	43.0	59.0	56.0	51.0
ML 3	11:00 a.m.	53.4	66.5	42.5	55.5	50.5	45.5
ML 4	12:30 p.m.	56.6	71.5	43.5	59.5	53.5	49.0
ML 5	2:00 p.m.	44.4	60.5	42.0	49.0	45.5	44.0

Monitoring Locations: ML 1: Jacobs residence at 21714 N Vallejo Street. ML 2: Keeps residence at 38068 State Route 299. ML 3: Polley residence at 37497 Mountain View Road. ML 4: First Baptist Church of Burney at 20428 Poplar Street. ML 5: Baker residence at 37127 Serpentine Lane. (Source: TMP 1999a, AFC § 6.4.2.2 and Table 6.4-5).

SIGNIFICANCE CRITERIA

The most stringent noise limitation required by any of the applicable LORS will be the controlling criterion in the design of the noise control features of the project. In this case, the most stringent criterion is the nighttime noise level (L_{eq}) of 50 dBA as specified in the Shasta County General Plan. The level is applicable 100 feet from the nearest residence approximately 1,800 feet from the site.

The significance of a noise impact is also a function of the change or increase in noise levels over existing ambient noise levels at any noise-sensitive receptor. A project related increase of 5 dBA or greater is considered significant by Energy Commission staff.

ENVIRONMENTAL NOISE IMPACTS

Noise will be produced at the powerplant site during the operation of the project and at the power plant site and along the corridors for linear project features during the construction phase. This assessment includes impacts from both construction and operation activities and their potential effects at the nearest sensitive receptors, and to power plant operations personnel. An essential part of this assessment is a comparison of expected noise levels with acceptable noise levels presented in applicable LORS, and with existing background levels at noise-sensitive receptors.

CONSTRUCTION NOISE

POWER PLANT

Typical construction noise levels generated by equipment at the project site are given in (**NOISE:** Table 4) below. The equipment type, equipment source level range (from quiet to poorly maintained), the maximum expected equipment to be used, and the worst-case cumulative effects (i.e., all equipment on at once and in one stationary location) are provided.

NOISE: Table 4
Anticipated Construction Activities
and Resultant Noise Levels

Construction Phase/ Equipment Type	Source Level @ 50 feet (dBA)	Maximum Number Expected	Cumulative Effects (dBA)
Site Clearing and Preparation			
Backhoe	72-92	3	76-96
Front Loader	72-74	3	76-78
Bulldozer	75-95	2	78-98
Backhoe	72-92	2	75-95
Water Truck	82-95	1	82-95
Dump Truck	82-95	4	88-101
Grading/Trenching			
Earth Mover	80-92	5	86-98
Bulldozer	75-95	2	78-98
Compactor	72-75	1	72-75
Backhoe	72-92	2	75-95
Water Truck	82-95	1	82-95
Dump Truck	82-95	4	88-101
Foundation/Building Construction			
Crane	75-88	2	78-91
Pile Driver	94-105	1	94-105
Loader	72-74	1	72-74
Bulldozer	75-95	1	75-95
Concrete Pump	82-84	1	82-84
Haul Trucks	82-95	4	88-101
Site Clean-up			
Bulldozer	75-95	1	75-95
Blade Scraper	80-92	1	80-92
Paving Equipment	86-88	1	86-88
Compactor	72-75	3	76-79
Water Truck	82-95	1	82-95
Haul Trucks	82-95	6	89-102

(Source: TMP 1999a, AFC § 6.4.2.4 and Table 6.4-7)

Major construction phases consist of site clearing and preparation, foundation construction, building and equipment construction, site clearing and facility start-up. Noise emissions will vary with each phase of construction.

Site clearing and preparation will require the use of heavy diesel-powered earthmoving equipment. Foundation construction will primarily involve concrete handling equipment and some earthmoving equipment for backfill. The building and equipment installation will involve mobile cranes, equipment delivery, impact wrenches, and air compressors. Site cleanup and facility startup would generally result in minimal noise emissions.

LINEAR FACILITIES

The natural gas tie-in line and water pipeline will be installed concurrent with the construction of foundations. Construction of these pipelines will involve trenching and installation of the line.

COMMUNITY NOISE EXPOSURE (CONSTRUCTION)

Steam Blows

Typically, the steam blows create the loudest noise, inherent in the construction of all projects incorporating a steam turbine. After erection and assembly of the feedwater and steam systems, the piping and tubing that comprises the steam path has accumulated dirt, rust, scale, and construction debris such as weld spatter, dropped welding rods, and the like. If the plant were started up without thoroughly cleaning out these systems, all this debris would find its way into the steam turbine, quickly destroying the machine.

In order to prevent this, before connecting the steam system to the turbine, the steam line is temporarily routed to the atmosphere. Steam is then raised in the HRSG or a temporary boiler and allowed to escape to the atmosphere through the steam piping. This flushing action, referred to as a steam blow, is quite effective at cleaning out the steam system piping. A series of short steam blows, lasting two or three minutes each, is performed several times daily over a period of two or three weeks. The applicant anticipates performing the steam blow activities during the daytime hours for a period not to exceed 10 working days. At the end of this procedure, the steam line is connected to the steam turbine, which is then ready for operation.

MITIGATION MEASURES (POWER PLANT)

Uncontrolled steam blow can produce noise levels as loud as 130 dBA at a distance of 50 feet. The applicant proposes to modify the steam blow process by decelerating and de-superheating the steam prior to exiting the vent stack. To further reduce noise, a by-pass stack will be used to direct the steam flow and the noise away from the sensitive receptors. This method should reduce the noise level to approximately 90 dBA at a distance of 50 feet. An additional reduction of 31 dBA is anticipated due to topographic attenuation: Δ Loss = $20Log_{10}(1{,}800ft/50ft_{REF})$ = 31.1dBA. In other words, approximately 31 dBA of noise reduction is expected between the source and receiver due to topographic (spherical) attenuation. This attenuation results in construction noise levels that will be at or below the current ambient noise levels at the nearest sensitive receptor. Consequently, except for steam blow activity, no mitigation measures are required for construction noise impacts.

Construction noise is short-term, and if the construction equipment is maintained properly, and if heavy construction is performed during daytime hours, then, construction noise is not likely to require additional mitigation. Staff has proposed a condition of certification (See condition of certification **NOISE-6**) restricting the applicant to perform noisy construction during daytime hours. Furthermore, residences can use the complaint process (See condition of Certification **NOISE-2**) to report unacceptable noise conditions.

With the above mitigation, the nearest sensitive receptor will be subjected to approximately 59 dBA. Staff recommends that such mitigation measures proposed above be used during the steam blow activity. Staff proposes a condition of certification (see proposed Condition of Certification **NOISE-4** below) to assure compliance.

Alternatively, the project owner may elect to employ a new, quieter steam blow process, variously referred to as QuietBlow® or Silentsteam™. This method uses lower pressure steam over a continuous period of approximately 36 hours. Resulting noise levels reach only about 80 dBA at 100 feet, equivalent to 40 to 45 dBA at the nearest residence. This noise level complies with the Shasta County noise element of the general plan. The applicant proposes to use this new technology (TMP 1999g, Response to Data Request #85). Staff proposes a condition of certification (see proposed Condition of Certification **NOISE-5** below) to assure compliance. Staff also proposes a notification process (see proposed Condition of Certification **NOISE-1** below) to make neighbors aware of impending steam blow activity.

MITIGATION MEASURES (LINEAR FACILITIES)

Noise associated with construction of the electrical transmission tie-in line will be lower than noise associated with construction of the facility, as less equipment will be used. Reconductoring of the PG&E transmission lines will result in minimal noise levels, as the reconductoring will be short-term in any one location and will involve no more equipment than routine line maintenance. One or two locations may be inaccessible by standard access roads; helicopters may be used in these places. Because of the remoteness and inaccessibility of these locations and the absence of sensitive noise receptors, no noise impacts are expected. For noise concerns to biological species, please see the **Biological Resources** testimony.

WORKER NOISE EXPOSURE (CONSTRUCTION)

POWER PLANT AND LINEAR FACILITIES

A reference distance of 50 feet was used in the AFC to evaluate on-site construction noise levels and their potential impacts on workers. The noise levels will vary significantly depending on whether a worker is closer to or conducting a noisy activity, but the L_{eq} levels are projected to average between 75 and 85 dBA during the first four phases of construction. Undoubtedly, some workers will occasionally be exposed to noise levels above 85 dBA[2] during construction. The applicant predicts that construction noise levels will not reach levels that require worker protection, but will put in place the use of engineering controls, administrative controls, and hearing protection devices (TMP 1999a, AFC § 6.4.4.2 and AFC page 6.4-29).

To ensure that workers are adequately protected, staff has proposed a condition of certification (see proposed Condition of Certification **NOISE-3**, below).

OPERATIONAL NOISE

POWER PLANT

Unmitigated operation of the proposed facility results in property line noise levels that are considered "conditionally acceptable" according to the Shasta County General Plan. Accordingly, mitigation of key noise generating equipment will be considered. Mitigation in the form of structural enclosure of key power production equipment will be implemented. Primary areas targeted were found to be turbine assemblies and synchronous generators. Application of structural attenuation was found to produce overall noise levels in compliance with applicable threshold criteria and resulted in no residual impacts.

Receptor Identification within 5 dBA Ambient Noise Contours. An examination of the proposed Facility design was performed to ascertain if any sensitive receptors were located within the +5dBA-over-ambient noise contours surrounding the powerplant site. No sensitive receptors were identified within these contours.

The loudest noise generator will be the HRSGs, producing sound level of 71 dBA L_{dn} at the powerplant property line (ML #1). The current ambient level at the site was measured at 60.3 dBA L_{dn} (ML #1). Thus, the proposed project is expected to produce a level of approximately 11 dBA over the current ambient noise. Using a spherical propagation rule, the 71-dBA-noise level will attenuate to approximately 42 dBA at 100 feet[3] from the nearest sensitive receptor. This level of noise is not expected to cause impacts that would require additional mitigation.

COMMUNITY NOISE IMPACTS (OPERATION)

During its operating life, the project will represent essentially a steady, continuous and broadband noise source day and night. Occasional short-term increases in noise level will occur as steam relief valves open to vent pressure, or during startup or shutdown as the plant transitions to and from steady-state operation. At other times, such as when the plant is shut down for lack of dispatch or for maintenance, noise levels will decrease.

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[2] OSHA does not consider noise levels of 85 dBA or less hazardous to employee health.

[3] Shasta County (see **NOISE-Table 1**) requires that in rural areas, the exterior noise level standard shall be applied at a point 100 feet away from the residence.

Expected operational noise levels are shown in (**NOISE:** Table 5). The primary noise sources include: two combustion turbine generators (CTGs) and associated CTG air inlets, two heat recovery steam generators (HRSGs), one steam turbine generator (STG), cooling tower fans, transformer areas, feed pumps (e.g., boiler, return, and circulation), and ancillary switchgear. The major noise emitting sources were modeled to estimate noise levels at the nearest property boundary to the east and west, and the nearest residence.

Noise associated with the CTG air inlets was not modeled because specific estimates of noise generation were not available; however, the CTG air inlets' position in the center of the site away from the site boundary make it unlikely that this source will result in higher property line noise levels than other sources. Furthermore, the air inlets will be configured to minimize noise impacts.

NOISE: Table 5
Expected Resultant Operational
Noise Levels in dBA (Unmitigated)

			Resultant Noise Levels (dBA)		
Equipment	Source Level @50'	Number Used	Nearest Property Line		Nearest Residence
			(East)	(West)	
Gas Turbine	85	2	77.9	71.9	61.3
AC Generator	85	3	86.5	69.1	61.3
Cooling Tower Fan	71	8	72.5	68.9	53.3
HRSG	82	2	81.0	65.0	58.3
Steam Turbine	80	1	69.9	63.9	53.2
Transformer Package	72	3	63.9	64.7	50.0
Boiler Pump	74	2	66.9	58.1	50.3
Circulation Pump	72	8	69.9	68.2	54.3
Return Pump	72	2	63.9	62.2	48.3
Switch Yard Gear	65	3	56.9	57.7	43.0
		SUM CNEL (Σ)	88.3	77.0	65.4

(Source: TMP 1999a, AFC § 6.4.3 and Table 6.4-9). Based upon assumed operational equipment

FREQUENCY (TONAL) CHARACTERISTICS AND INTERMITTENT NOISES

One possible source of noise annoyance would be strong tonal noises, individual sounds that, while not louder than the permissible levels, stand out in sound quality. To ensure the avoidance of such tonal sound, the noise control design of the TMPP can be balanced to bring as many noise sources as possible to the same relative sound level, causing them all to blend without any one source standing out.

The frequency characteristics associated with the proposed operational equipment are shown in (**NOISE:** Table 6 below). The data shown is representative of individual equipment types and is based upon past field studies.

NOISE: Table 6
Frequency Characteristics of
Proposed Operational Equipment

Equipment	Source Level @ 50 ft. (dBA)	Dominant Frequencies (Hz)						
		125	250	500	1,000	2,000	4,000	8,000
Gas Turbine	85	•		•	•	•		
AC Generator	85			•	•	•	•	
Cooling Tower Fan	71	•	•	•	•			
HRSG	82		•	•	•	•		
Steam Turbine	80	•	•	•	•	•		
Transformer Package	72				•	•		•
Boiler Pump	74	•	•	•				
Circulation Pump	72	•	•	•				
Return Pump	72	•	•	•	•			
Switch Yard Gear	65	•						

(Source: TMP 1999a, AFC § 6.4.3 and Table 6.4-9)

Past studies have shown that the dominant noise generator at a power plant site is the turbine/synchronous generator assembly. The dominant spectral content lies within the 500 to 2000 Hz frequency band. These levels, although audible, would not impair hearing if properly mitigated.

Another potentially annoying source of noise from a power plant is the intermittent or occasional actuation of steam relief valves. The hissing noise from these valves can be largely mitigated by the installation of adequate mufflers. To ensure that adequate measures are taken to mitigate tonal and intermittent noise sources, staff has proposed measures (see proposed Condition of Certification **NOISE-4**, below) to ensure that tonal and intermittent steam relief noises are not allowed to cause a problem.

LINEAR FACILITIES

High voltage transmission lines can produce a hissing sound as a result of corona discharge from the conductors. The noise level is a function of voltage and is most evident at higher voltages. Power lines with voltages less than 230 kV rarely produce an audible corona discharge noise because there is little or no discharge at these lower voltages. The sound from 230 kV lines, as proposed for TMPP, is generally inaudible at distances greater than 50 feet from the conductor bundle except during rainy or high humidity conditions.

A switchyard located at the point of interconnection with the existing 230 kilovolt (kV) transmission line will also emit a low level of noise similar to the transmission line. The noise from the switchyard will generally be inaudible at the switchyard property line. The noise from the switchyard will not be audible at the nearest residence, which is more than 2,000 feet from the switchyard.

SHASTA COUNTY MITIGATION RECOMMENDATIONS

Mitigation in the form of equipment enclosure will be employed to reduce property line noise exposure to levels that meet Shasta County's "conditionally acceptable" property line CNEL of 75 dBA. The proposed mitigation design, in the form of required minimum structural attenuation, is given in (**NOISE:** Table 7). It is noted that a 10-dB margin has been added to the required attenuation for the turbine, generator, and cooling tower fans to compensate for the nighttime CNEL penalty.

The proposed attenuation levels should be incorporated into the engineering design once final plans are completed. Upon implementation, no significant or residual noise impacts would remain.

NOISE: Table 7
Expected Resultant Operational
Noise Levels (Mitigated) (dBA)

				Resultant Noise Levels (dBA)		
Equipment	Source Level @ 50 feet	Number Used	Design Attenuation	Nearest Property Line (East)	Nearest Property Line (West)	Nearest Residence
Gas Turbine	85	2	20	57.9	51.9	41.3
AC Generator	85	3	20	66.5	49.1	41.3
Cooling Tower Fans	71	8	8	64.5	60.9	45.3
HRSG	82	2	10	71.0	55.0	48.3
Steam Turbine	80	1	20	49.9	43.9	33.2
Transformer Package	72	3	5	58.9	59.7	45.0
Boiler Pump	74	2	5	61.9	53.1	45.3
Circulation Pumps	72	8	5	64.9	63.2	49.3
Return Pump	72	2	5	58.9	57.2	43.3
Switch Yard Gear	65	3	5	51.9	52.7	38.0
SUM CNEL (S)				**74.3**	**67.6**	**53.8**

(Source: TMP 1999a, AFC § 6.4.3 and Table 6.4-9). Based upon planned operational equipment

Based upon the findings presented in (**NOISE:** Table 7), the mitigated noise levels will not exceed the 55 dBA Daytime noise levels and will exceed by 3.8 dBA of Nighttime noise guidelines in the Shasta County General Plan. Based upon analysis presented in (NOISE: Table 7) additional mitigation measures will be required in order for the powerplant operational noise levels to be at or below 50 dBA Nighttime noise levels as provided in Noise Element of the Shasta County General Plan.

CAL-OSHA MITIGATION RECOMMENDATIONS

Typically, individual power plant equipment can be provided that does not exceed a mitigated sound pressure level of 85 dBA at 3 feet from the equipment face and 5 feet above the ground. However, noise levels in some areas within a power plant typically exceed 85 dBA due to the additive effect of all nearby equipment as well as the effect of sound reflection and reverberation. Special noise control measures, such as silencers, acoustical enclosures, or insulation and acoustical lagging, may be considered to reduce in-plant noise levels.

These noise controls, however, are not always practical for reasons such as maintenance access, heat buildup, space limitations, and safety. Therefore, noise levels in some areas may exceed a sound pressure level of 85 dBA. OSHA and Cal-OSHA noise exposure limits would be satisfied using hearing protection within areas exceeding this level. Staff has proposed measures (see proposed Condition of Certification **NOISE-5**, below) to ensure compliance.

CUMULATIVE IMPACTS

The cumulative impacts discussion for the TMPP is based on CEQA and the CEQA Guidelines which require that the discussion of cumulative impacts be "guided by the standards of practicality and reasonableness" (Public Resources Code (PRC) §21083(b)); and that "the discussion include a list of past, present, and reasonably anticipated future projects producing related or cumulative impacts" (California Code of Regulations (CCR) §15130(b)(1)(A)). The CEQA Guidelines require that cumulative impacts are discussed when they are significant, and that the discussions of cumulative impacts reflect the severity of the impacts and their likelihood of occurrence. However, the Guidelines state that the cumulative impacts discussion need not be provided in as great detail as is provided for the proposed project.

Therefore, the purpose of this analysis is to:

5. Identify past, present, and reasonably foreseeable actions in the project area that could affect noise at the TMPP.
6. Determine if the impacts of the TMPP and the other actions would overlap in time or geographic extent.
7. Determine if the impacts of the proposed project would interact with, or intensify, the impacts of the other actions.
8. Identify any potentially significant cumulative impacts.

Projects identified for consideration in this discussion of cumulative impacts include those: 1) where an application has been submitted to local jurisdictions for required approvals and permits; and/or 2) that has been previously approved and may be implemented in the near future.

There are no projects within the TMPP Area of Influence. For this discussion of cumulative impacts, the general geographic area of influence is defined as an approximate 2-mile radius around the power plant, or within 1 mile of the linear facilities. The Biomass Plant was included as part of the background noise level.

FACILITY CLOSURE

Upon closure of the facility, all operational noise will cease; no further adverse impacts from operation will be possible. The remaining potential noise source will be that caused by dismantling of the structures and equipment, and any site restoration work that may be performed. Since this noise will be similar to that caused by the original construction of the project, it can be treated similarly. That is, noisy work can be performed during daytime hours, with machinery and equipment properly equipped with mufflers. Any noise laws, ordinances, regulations and standards then in existence would apply; applicable Conditions of Certification included in the Energy Commission Decision would also apply unless properly modified.

REVISED NOISE ANALYSIS

On August 21, 2000, Three Mountain Power filed a set of mitigation measures, referred to as the "Mitigation Plan". The noise evaluation contained in the AFC was based on the power plant design prior to the implementation of the Mitigation Plan. Because the Mitigation Plan includes additional equipment (the air-cooled condenser), and involves a reconfiguration of the plant site design, the noise analysis has been revised to reflect the effects of the Mitigation Plan.

As stated in the AFC, the nearest residence that could be affected by the noise from the project is located approximately 1,400 feet from the western fence line of the project site. Other residences are located approximately 1,800 feet northwest of the project boundary. Other noise sensitive receptors such as schools are located within a 2-mile radius of the project site. No additional noise-sensitive receptors would be affected due to the implementation of the Mitigation Plan, nor is there a substantive change in the definition of the area impacted by the project, which is the area where there is a potential increase of 5 dBA or more during either construction or operation of the project over existing background noise levels.

Initial noise measurements were made between November 6 and November 8, 1998, for approximately 48 hours. The results of these noise measurements are provided in the AFC and a summary of the results is presented as **NOISE-Table 3.** To verify the ambient noise measurements and to reflect the current conditions at the nearest noise-sensitive receptors, an additional 25-hour noise survey was made at the nearest residence on July 26 and 27, 2000. Results of the 25-hour sound level measurements are shown as Table 3.5.1 [Ref. TMP 2000a].

The project has included an air-cooled condenser as part of the Mitigation Plan. No other major new noise sources are proposed. A revised project noise analysis was conducted to include this new noise source. Furthermore, the facility plot plan was reconfigured to allow for a more efficient fit of the equipment included in the Mitigation Plan of the site.

The primary noise sources at the Three Mountain Power Project include: two combustion turbine generators (CTGs) and associated CTG air inlets, two heat recovery steam generators (HRSGs), one steam turbine generator (STG), wet cooling tower fans, air-cooled condenser fans, transformer areas, feed pumps and ancillary switchgear. The major noise sources were modeled to estimate the revised noise levels at the nearest property boundary to the east and west, at the nearest residences. Noise source characteristics are presented in Table 3.5.2 [Ref. TMP 2000a].

PROJECTED NOISE LEVELS

Acoustical calculations were performed to estimate the sound level from the project at 100 feet from the closed noise-sensitive receptor. It was assumed that noise from project components would decay based on "point source" acoustical characteristics. A point source decays sound at a rate of 6 dB per doubling of the distance from the source-receiver pair.

Based on the above assumptions, the estimated sound level 100 feet from the nearest noise-sensitive receptor is estimated at 50 dBA. This noise level does not exceed the measured sound level at the nearest receptor. This noise level also meets the requirements of the Shasta County General Plan Noise Element. The original conclusion that the project has no significant impacts in the noise resource area is unchanged by the Mitigation Plan. No additional Conditions of Certification will therefore be necessary.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

On February 17, 2000 J. Robert (Bob) Murray submitted a declaration to the Energy Commission. In his declaration, Mr. Murray states that the project will be designed to meet Shasta County's "conditionally acceptable" property line noise level of 75 dBA" CNEL.

Please note that the noise levels will not exceed 55 dBA Daytime noise levels and the project is conditioned to meet 50 dBA Nighttime noise levels as provided in Noise Element of the Shasta County General Plan. Conditions have been proposed to ensure that the above requirements are met, see Condition of Certification **NOISE-4**. There are other safeguards built into the process, such as the noise complaint process, see Condition of Certification **NOISE-2**, and the requirements that the project owner perform a community noise measurement after the project first achieves an output of 80 percent or greater of rated capacity, see Condition of Certification **NOISE-4**.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff concludes that the TMPP will likely be built and operated to comply with all applicable noise laws, ordinances, regulations and standards. Staff further concludes that the TMPP will likely create no significant adverse noise impacts. The TMPP will likely represent an unobtrusive, nearly undetectable addition to existing noise levels.

RECOMMENDATIONS

Staff recommends the conditions of certification proposed below be included in the Commission Decision.

PROPOSED CONDITIONS OF CERTIFICATION

NOISE-1 At least 15 days prior to the start of construction (defined as start of rough grading) of the TMPP and again at least 15 days prior to the commencement of steam blow activity, the project owner shall notify all residents within a 2-mile radius of the project site, by mail or other effective means. The project owner shall establish a telephone number for use by the public to report any undesirable noise conditions associated with the construction and operation of the TMPP. If the telephone is not staffed 24 hours per day, the project owner shall include an automatic answering feature, with date and time stamp recording, to answer calls when the phone is unattended. This telephone number shall also be posted at the TMPP site during construction in a manner visible to passersby. This telephone number shall be maintained until the TMPP has been operational for at least one year.

Verification: The project owner shall transmit to the Compliance Project Manager (CPM) in the first monthly construction report following the start of rough grading, a statement signed by the project manager attesting that the above notification has been performed, describing the method of that notification, and including a sample letter, poster or other notice, as appropriate. This statement shall also attest that the telephone number has been established and posted at the power plant site.

NOISE-2 Throughout the construction and operation of the TMPP, the project owner shall document, investigate, evaluate, and attempt to resolve all project related noise complaints.

Protocol: The project owner shall:

1. use the Noise Complaint Resolution Form (see below for an example), or functionally equivalent procedure acceptable to the CPM, to document and respond to each noise complaint;
2. attempt to contact the person(s) making the noise complaint within 24 hours;
3. conduct an investigation to determine the source of noise related to the complaint;
4. take all feasible measures to reduce the noise at its source if the noise is project related, and
5. submit a report documenting the complaint and the actions taken. The report shall include a complaint summary and the results of noise reduction efforts; and if obtainable, a signed statement by the complainant, stating that the noise problem is resolved to complainant's satisfaction.

Verification: Within 30 days of receiving a noise complaint, the project owner shall file a copy of the Noise Complaint Resolution Form, or similar instrument approved by the CPM, with Shasta County and with the CPM documenting the resolution of the complaint. If mitigation is required to resolve a complaint, and the complaint is not resolved within a 30-day period, the project owner shall submit an updated Noise Complaint Resolution Form when the mitigation is finally implemented.

NOISE-3 Prior to the start of construction of TMPP, the project owner shall submit to the CPM for review a noise control program. The noise control program shall be used to reduce employee exposure to high noise levels during construction and also to comply with applicable OSHA standards.

Verification: At least 30 days prior to the start of rough grading the project owner shall submit to the CPM the above referenced program. The project owner shall make the program available to OSHA upon request.

NOISE-4 Upon the TMPP first achieving an output of 80 percent or greater of rated capacity, the project owner shall conduct a 25-hour community noise survey, utilizing the same monitoring sites employed in the pre-project ambient noise survey as a minimum. The survey shall also include the octave band pressure levels to ensure that no new pure-tone noise components have been introduced. No single piece of equipment shall be allowed to stand out as a dominant source of noise that draws complaints. Steam relief valves shall be adequately muffled to preclude noise that draws complaints. The noise contributed by the TMPP operation at 100 feet from the nearest residence shall not exceed 50 dBA L_{eq} (night) under normal operating conditions including startups and shutdowns. If the results from the survey indicate that power plant noise levels are in excess of 50 dBA L_{eq} (night) at 100 feet from the nearest residence, additional mitigation measures shall be implemented to reduce noise to a level of compliance with this limit. The mitigation measures (to be employed as required) may include (but not be limited to):

1. Provide standard outdoor/weather enclosures for the combustion turbine generator packages.
2. Provide air inlet silencers for the combustion turbines.

Protocol: The measurement of power plant noise for purposes of demonstrating compliance with this Condition may alternatively be made at an acceptable location closer to the plant (e.g. 400 to 1,000 feet from the plant boundary) and this measured level then mathematically extrapolated to determine the plant noise contribution at the nearest sensitive receptor. However, notwithstanding the use of this alternative method for determining the noise level, the character of plant noise shall be evaluated at the nearest sensitive receptor to determine the presence of pure tones or other dominant sources of plant noise.

Verification: Within 30 days after completing the survey, the project owner shall submit a summary report of the survey to Shasta County and the CPM. Included in the report will be a description of any additional mitigation measures necessary to achieve compliance with the above listed noise limits, and a schedule, subject to CPM approval, for implementing these measures. Within 30 days of completion of installation of these measures, the project owner shall submit to the CPM a summary report of a new noise survey, performed as described above and showing compliance with this condition.

NOISE-5 The project owner shall conduct an occupational noise survey to identify the noise hazardous areas in the facility. The survey shall be conducted within thirty (30) days after the facility is operating at an output of 80% of rated capacity or greater, and shall be conducted by a qualified person in accordance with the provisions of Title 8, California Code of Regulations sections 5095-5100 (Article 105) and Title 29, Code of Federal Regulations, Part 1910. The survey results shall be used to determine the magnitude of employee noise exposure. The project owner shall prepare a report of the survey results and, if necessary, identify proposed mitigation measures that will be employed to comply with the applicable state and federal regulations.

Verification: Within 30 days after completing the survey, the project owner shall submit the noise survey report to the CPM. The project owner shall make the report available to OSHA upon request.

NOISE-6 Construction and construction related activity (that which causes off-site annoyance, as evidenced by the filing of a legitimate noise complaint) shall be restricted to the hours of: 7 a.m. to 7 p.m. on weekdays and from 8 a.m. to 6 p.m. on weekends and holidays.

Verification: The project owner shall transmit to the CPM in the first Monthly Construction Report a statement certifying that the above restrictions will be observed throughout the construction of the project.

NOISE COMPLAINT RESOLUTION FORM

Three Mountain Power Project
(99-AFC-2)

NOISE COMPLAINT LOG NUMBER ________________________

Complainant's name and address:

Phone number: ________________________

Date complaint received: ________________________
Time complaint received: ________________________

Nature of noise complaint:

Definition of problem after investigation by plant personnel:

Date complainant first contacted: ________________________

Initial noise levels at 3 feet from noise source _________ dBA Date: _____________

Initial noise levels at complainant's property: __________ dBA Date: ____________

Final noise levels at 3 feet from noise source: ________ dBA Date: _____________

Final noise levels at complainant's property: __________ dBA Date: ____________

Description of corrective measures taken:

Complainant's signature: ________________________ Date: ____________

Approximate installed cost of corrective measures: $ ____________
Date installation completed: ____________
Date first letter sent to complainant: ____________ (copy attached)
Date final letter sent to complainant: ____________ (copy attached)

This information is certified to be correct:

Plant Manager's Signature: ________________________

(Attach additional pages and supporting documentation, as required).

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TMP 2000a. Detailed Mitigation Plan and Analysis of Impact Assessments in Resource Areas Affected by the Mitigation Plan. August 21, 2000.

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NOISE: APPENDIX A
FUNDAMENTAL CONCEPTS OF COMMUNITY NOISE

Noise levels can be measured in a number of ways. One common measurement, the equivalent sound level (L_{eq}), is the long-term A-weighted sound level that is equal to the level of a steady-state condition having the same energy as the time-varying noise, for a given situation and time period. (See NOISE: Table A1, below.) A day-night (L_{dn}) sound level measurement is similar to L_{eq}, but has a 10 dB weighting added to the night portion of the noise because noise during night time hours is considered more annoying than the same noise during the day.

NOISE Table A1
Definition of Some Technical Terms Related to Noise

Terms	Definitions
Decibel, dB	A unit describing the amplitude of sound, equal to 20 times the logarithm to the base 10 of the ratio of the pressure of the sound measured to the reference pressure, which is 20 micropascals (20 micronewtons per square meter).
Frequency, Hz	The number of complete pressure fluctuations per second above and below atmospheric pressure.
A-Weighted Sound Level, dB	The sound pressure level in decibels as measured on a Sound Level Meter using the A-weighting filter network. The A-weighting filter de-emphasizes the very low and very high frequency components of the sound in a manner similar to the frequency response of the human ear and correlates well with subjective reactions to noise. All sound levels in this testimony are A-weighted.
L_{10}, L_{50}, & L_{90}	The A-weighted noise levels that are exceeded 10%, 50%, and 90% of the time, respectively, during the measurement period. L_{90} is generally taken as the background noise level.
Equivalent Noise Level L_{eq}	The energy average A-weighted noise level during the Noise Level measurement period.
Community Noise Equivalent Level, CNEL	The average A-weighted noise level during a 24-hour day, obtained after addition of 5 decibels to levels in the evening from 7 p.m. to 10 p.m. and after addition of 10 decibels to sound levels in the night between 10 p.m. and 7 a.m.
Day-Night Level, L_{dn}	The Average A-Weighted noise level during a 24-hour day, obtained after addition of 10 decibels to levels measured in the night between 10 p.m. and 7 a.m.
Ambient Noise Level	The composite of noise from all sources, near and far. The normal or existing level of environmental noise at a given location.
Intrusive Noise	That noise that intrudes over and above the existing ambient noise at a given location. The relative intrusiveness of a sound depends upon its amplitude, duration, frequency, and time of occurrence and tonal or informational content as well as the prevailing ambient noise level.
Source: California Department of Health Services 1976.	

In order to help the reader understand the concept of noise in decibels (dBA), NOISE: Table A2 has been provided to illustrate common noises and their associated dBA levels.

NOISE Table A2
Typical Environmental and Industry Sound Levels

Source and Given Distance from that Source	A-Weighted Sound Level in Decibels (dBA)	Environmental Noise	Subjectivity/ Impression
Civil Defense Siren (100')	140-130		Pain Threshold
Jet Takeoff (200')	120		
Very Loud Music	110	Rock Music Concert	Very Loud
Pile Driver (50')	100		Very Loud
Ambulance Siren (100')	90	Boiler Room	Very Loud
Freight Cars (50')	85		
Pneumatic Drill (50')	80	Printing Press Kitchen with Garbage Disposal Running	Loud
Freeway (100')	70		Moderately Loud
Vacuum Cleaner (100')	60	Data Processing Center Department Store/Office	
Light Traffic (100')	50	Private Business Office	Quiet
Large Transformer (200')	40		
Soft Whisper (5')	30	Quiet Bedroom	
	20	Recording Studio	
	10		Threshold of Hearing
Source: Peterson and Gross 1974			

SUBJECTIVE RESPONSE TO NOISE

The adverse effects of noise on people can be classified into three general categories:

Subjective effects of annoyance, nuisance, dissatisfaction.
Interference with activities such as speech, sleep, and learning.
Physiological effects such as anxiety or hearing loss.

The sound levels associated with environmental noise, in almost every case, produce effects only in the first two categories. Workers in industrial plants can experience noise effects in the last category. There is no completely satisfactory way to measure the subjective effects of noise, or of the corresponding reactions of annoyance and dissatisfaction, primarily because of the wide variation in individual tolerance of noise.

One way to determine a person's subjective reaction to a new noise is to compare the level of the existing (background) noise, to which one has become accustomed, with the level of the new noise. In general, the more the level or the tonal variations of a new noise exceed the previously existing ambient noise level or tonal quality, the less acceptable the new noise will be, as judged by the exposed individual.

With regard to increases in A-weighted noise levels, knowledge of the following relationships (Kryter 1970) can be helpful in understanding the significance of human exposure to noise.

1. Except under special conditions, a change in sound level of one dB cannot be perceived.
2. Outside of the laboratory, a 3-dB change is considered a barely noticeable difference.
3. A change in level of at least five dB is required before any noticeable change in community response would be expected.
4. A 10-dB change is subjectively heard as an approximate doubling in loudness and almost always causes an adverse community response.

COMBINATION OF SOUND LEVELS

People perceive both the level and frequency of sound in a non-linear way. A doubling of sound energy (for instance, from two identical automobiles passing simultaneously) creates a three dB increase (i.e., the resultant sound level is the sound level from a single passing automobile plus three dB). The rules for decibel addition used in community noise prediction are:

NOISE Table A3
Addition of Decibel Values

When two decibel values differ by:	Add the following amount to the larger value
0 to 1 dB	3 Db
2 to 3 dB	2 Db
4 to 9 dB	1 dB
10 dB or more	0
Figures in this table are accurate to ± 1 dB.	

Source: Thumann, Table 2.3

OSHA noise regulations are designed to protect workers against the effects of noise exposure, and list permissible noise level exposure as a function of the amount of time to which the worker is exposed:

NOISE Table A4
OSHA Worker Noise Exposure Standards

Duration of Noise (Hrs/day)	A-Weighted Noise Level (dBA)
8.0	90
6.0	92
4.0	95
3.0	97
2.0	100
1.5	102
1.0	105
0.5	110
0.25	115

Source: OSHA Regulation

RELATIONSHIPS

L_{dn} = 10 log (1/24)[15x10$^{(Ld/10)}$ + 9x10$^{(Ln+10)/10}$]

<u>Note:</u> the 10-dB weighting added to the nighttime noise level. Daytime and nighttime are 15 hours (0700~2200 hrs) and 9 hours (2200~0700 hrs) respectively. L_d and L_n are the L_{eq} values over the 15 and 9 hours respectively. L_{dn} does not contain any consideration for tonal sounds, since it is derived from L_{eq} measurements.

CNEL is essentially the same as L_{dn}, except that different time segments are used in computation. The 24-hour period is divided into three segments instead of two. The day period (0700~1900 hours), evening (1900~2200 hours) and night (2200~0700 hours). The evening period is assigned 5-dB weighting and the nighttime is assigned 10-dB weighting. The extra 5 dB weighting during the evening results in higher values for CNEL that L_{dn}, but the difference is not statistically significant.

NOISE ATTENUATION

[L_p] (at x = r) = [L_p](at r = y) – 20log(x/y).

Where: x = distance to point where noise level is to be determined.
y = reference point.

Δ_{Loss} = 20log (x/y).

Special case where x = 2y
Δ_{Loss} = 20log (2y/y). = 20log (2) = 6

∴ As we double the distance, from a point source in free space, the noise level decreases by 6 dB.

PUBLIC HEALTH

Testimony of Obed Odoemelam, Ph.D.

INTRODUCTION

Operating the proposed Three Mountain Power Project (TMPP) would create combustion products and possibly expose workers and the general public to these pollutants as well as the toxic chemicals associated with other aspects of facility operations. The issue of possible worker exposure is addressed in the **Worker Safety and Fire Protection** section of this Preliminary Staff Assessment (PSA). Exposure to electric and magnetic fields (EMF) is addressed in the **Transmission Line Safety and Nuisance** section. The purpose of this public health analysis is to determine whether a significant health risk would result from public exposure to these chemicals and combustion by-products routinely emitted during project operations.

The exposure of primary concern in this section is to pollutants for which no air quality standards have been established. These are known as non criteria pollutants, toxic air pollutants, or air toxics. Those for which ambient air quality standards have been established are known as criteria pollutants. These criteria pollutants are identified in this section (along with regulations for their control) because of their usually significant contribution to the total pollutant exposure in any given area. Furthermore, the same control technologies may be effective for controlling both types of pollutants when emitted from the same source. Compliance with the required control technologies is discussed in the **Air Quality** section. When a project is proposed for an area with existing violations of any of the air quality standards, the health impacts of the criteria pollutant in question would be addressed in this Public Health section to assess the need for mitigation.

LAWS ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

The Clean Air Act of 1970 (42 U.S.C., section 7401 et seq.) required establishment of ambient air quality standards to protect the public from the effects of air pollutants. These standards have been established by the United States Environmental Protection Agency (EPA) for the major air pollutants: nitrogen dioxide, ozone, sulfur dioxide, carbon monoxide, sulfates, particulate matter with a diameter of 10 micron or less (PM10), and lead.

STATE

California Health and Safety Code section 39606 requires the California Air Resources Board (ARB) to establish California's ambient air quality standards to reflect the California-specific conditions that influence its air quality. Such standards have been established by the ARB for ozone, carbon monoxide, sulfur dioxide, PM10, lead, hydrogen sulfide, vinyl chloride and nitrogen dioxide. The same biological mechanisms underlie some of the health effects of most of these criteria pollutants as well as the non criteria pollutants. The California standards are listed together with the corresponding federal standards in the **Air Quality** section.

California Health and Safety Code section 41700 states that “No person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause or have a natural tendency to cause injury or damage business or property.”

The California Health and Safety Code section 39650 et seq. mandates that the California Environmental Protection Agency (Cal-EPA) establish safe exposure limits for toxic, non criteria air pollutants and identify the best available methods for their control. These laws also require that the new source review rules for each air district include regulations establishing procedures to control the emission of these pollutants. The toxic emissions from natural gas combustion are listed in ARB’s April 11, 1996 California Toxic Emissions Factors (CATEF) database for natural gas-fired combustion turbines. Cal-EPA has developed specific cancer potency estimates for assessing their related cancer risks at specific exposure levels. For non cancer-causing toxic air pollutants, Cal-EPA established specific no-effects levels (known as reference exposure levels) for assessing the likelihood of producing health effects at specific exposure levels. Such health effects would be considered significant only when exposure exceeds these reference levels. The Energy Commission staff (staff) uses these Cal-EPA potency estimates and reference exposure values in its health risk assessments.

California Health and Safety Code section 44300 et seq. requires facilities, which emit large quantities of criteria pollutants and any amount of non criteria pollutants to provide the local air district an inventory of toxic emissions. Such facilities may also be required to prepare a quantitative health risk assessment to address the potential health risks involved. The ARB and the Air Quality Management District will ensure implementation of these requirements for the proposed project.

LOCAL

The Shasta County Air Quality Management District (District) has no specific rules implementing Health and Safety Code section 44300. It does, however, require the results of a health risk assessment as part of the application for the Determination of Compliance. TMPP has complied with this requirement.

SETTING

According to information from the applicant, Three Mountain Power, LLC, (TMPP 1999a pages 1-8,and 6.9-1), the proposed facility will be located within a 40-acre site surrounded by land zoned for industrial use, rural residential use and timberland. This location is 1 mile away from the town of Burney in Shasta County, with a population of 3,500. The nearest residence to the site is approximately 1,400 feet away. The air quality in the Burney area is considered good since its air pollutant levels do not exceed federal air quality standards. However, as noted in the Air Quality section, the area sometimes exceeds the state's PM10 standards in the winter months mainly because of the use of wood-burning stoves and fire places. While it is appropriate to continue including the area's industrial sources in the search for solutions to the area's PM10 problem, staff considers a district-wide control program with respect to wood stove and fire place emissions, to be as significant as the one for these industrial sources in the effort to minimize the area's PM10 problem. A detailed mitigation plan has been provided by the applicant in this regard (TMPP 2000) and found acceptable by staff. This plan is intended to offset the project's PM10 emissions by reducing the contribution from area wood-burning stoves and fire places.

The applicant has provided a listing of locations with sensitive receptors such as children and the elderly, within a 6-mile radius from the facility (TMPP 1999a page 6.9-11). These sensitive receptors are usually more susceptible than the general population to the effects of environmental pollutants. Extra consideration is given to possible effects of exposure to these individuals in establishing exposure limits for environmental pollutants. Most of the area to be impacted by the project's pollutants is timberland.

METHOD OF ANALYSIS

Any non criteria pollutant-related impacts from this type of project would be mainly associated with its emissions from the combustion turbines, ammonia from the selective catalytic reduction (SCR) system, and toxic chemicals from the cooling towers. For criteria pollutants, the impacts of most significance would result from emissions from the turbines. Potential public exposure to the surrounding population is estimated through air dispersion modeling. After estimating the exposure levels, staff assesses whether these exposure estimates are below the applicable air quality standards or reference exposure levels in the case of non cancer effects. For noncriteria pollutants, staff compares the potential for exposure to levels whose related cancer risks are considered significant by regulatory agencies. The procedure for evaluating the potential for these cancer and non cancer health effects is known as a health risk assessment process and consists of the following steps:

- A hazard identification step in which each pollutant of concern is identified along health effects it can cause;
- A dose-response assessment step in which the relation between the magnitude of exposure and the probability of effects is established;
- An exposure assessment step in which the possible extent of pollutant exposures from a project is established for all possible pathways by dispersion modeling; and
- A risk characterization step in which the nature and often the magnitude of the possible human health risk is assessed and presented.

HEALTH EFFECTS ASSESSED

Health risks associated with a project can result from high-level exposure, which creates immediate-onset (acute) effects, or from prolonged low-level exposure, which creates chronic effects. Since non cancer effects are assumed to result after exposure above specific thresholds, an analysis of the potential for these effects will include, where possible, consideration of background levels of the toxic pollutants being assessed. Unfortunately, such background measurements are not usually available for the non criteria pollutants associated with natural gas combustion unless there are major sources in the area. Non criteria pollutants from combustion are generally emitted at relatively low levels compared to criteria pollutants. Background concentrations of non criteria pollutants are normally encountered at lower levels than criteria pollutants. Given the project area's compliance with all federal air quality standards (with the noted exception of the state's PM10 standard in the winter months), staff would not expect the non criteria pollutants to be encountered at significant background levels. Therefore, staff will assess the potential impacts of the project's toxic emissions only in terms of their direct emission levels without requiring measurements of background levels. The potential for significant PM10 impacts will also be assessed.

For natural gas-burning facilities such as the proposed TMPP, high-level exposure to toxic pollutants (which could cause acute effects) could occur only during major accidents and are not expected from routine operations when emissions are much lower. For criteria pollutants (such as PM10 in this case) which may be encountered at background levels high enough to violate their air quality standards, acute health impacts could result from any additions from the project. Long-term exposures could lead to chronic effects which the ambient air quality standard were established to prevent. Since acute impacts are not expected from exposure to the non criteria pollutants from TMPP and similar sources, effects of long-term, exposures are of greater concern than short-term effects in assessing the project's potential for public health impacts. Chronic effects from non criteria pollutant exposures may be related to cancer or health effects other than cancer.

The method used by regulatory agencies to assess the significance of non cancer health effects of criteria and non criteria pollutants is the hazard index method and is used to assess both acute and chronic effects. In this method, a hazard index is calculated for the individual non criteria pollutants by dividing projected exposure by the reference level for that pollutant. For the criteria pollutant, this hazard index value is obtained by dividing exposure levels by the applicable air quality standard. A hazard index of 1.0 or less suggests that acute or chronic effects would be unlikely. A value of more than 1.0 would point to the possibility of effects, but given the conservatism in the derivation process, is not regarded as definite evidence that such effects would occur. The indices for all pollutants are then added together to obtain an aggregate hazard index value for the project in question. A total index of 1.0 or less indicates a lack of potential effects from all pollutant exposures considered together. As with the individual pollutants, a value of more than 1.0 indicates that a more refined analysis is required to determine whether the project would pose an actual health risk, which might require mitigation.

POTENTIAL CANCER RISK

Cancer from carcinogenic exposure usually results from biological effects at the molecular level. Since such effects are currently assumed possible from every exposure to a carcinogen, the risk of cancer is generally considered by staff and other regulatory agencies as more sensitive than the risk of non cancer health effects. This accounts for the prominence of theoretical cancer risk estimates in the environmental risk assessment process. For any source of concern, the potential risk of cancer is obtained by multiplying the exposure estimate by the potency values for the individual carcinogens involved. The total project-related cancer risk is then obtained by adding together the risk values obtained for each of the individual carcinogens. This assessment process allows for calculation of only the upper bounds on the cancer risk. The actual risk will likely be lower and could indeed be zero.

STAFF'S SIGNIFICANCE CRITERIA

Various state and federal agencies specify different cancer risk levels as levels of significance with regard to specific sources. For example, a risk of 10 in a million is considered significant under the Air Toxics "Hot Spots" (AB 2588) and the Proposition 65 programs, and therefore, used as a threshold for public notification in cases of air toxics emissions from existing sources. For sources in California, all these risk values are calculated using the conservative guidelines in the previously noted CAPCOA guidelines. The Energy Commission staff considers a potential cancer risk of one in a million as the de minimis level, which is the level below which the related exposure is negligible, meaning that project operation is not expected to result in any increase in cancer. Above this level, further mitigation could be recommended after proper consideration of issues related to the limitations of the assessment process. For non carcinogenic pollutants, staff will consider significant health impacts unlikely when the hazard index estimate is 1.0 or less. If more than 1.0, staff would regard the related emissions as potentially significant from an environmental health perspective.

IMPACTS

PROJECT SPECIFIC IMPACTS

CONSTRUCTION PHASE IMPACTS

Potential risks to public health during construction may be associated with toxic substances disturbed during site preparation, and emissions from heavy equipment as noted for the project (TMPP 1999a pages 6.9-5). Potential impacts from emission of criteria pollutants from heavy equipment operation and particulates from site preparation are assessed in staff's **Air Quality** section in connection with the applicable air quality standards. That section also addresses compliance with applicable emission-limiting District rules together with the requisite conditions of certification. Since no hazardous substances were identified from the Environmental Site Assessment for the project (TMPP 1999a page 6.12-1), no significant pollutant-related public health impacts are anticipated from the relatively short-term construction-related earth moving activities involved. Effects from chronic exposures are not expected from these short-term activities.

DIRECT OPERATIONAL IMPACTS

Three Mountain Power conducted the health risk assessment for the project-related emissions of potential significance according to procedures specified in the 1993 California Air Pollution Control Officer's Association (CAPCOA) guidelines for sources of this type. Results of this assessment have been provided to staff, along with documentation of the assumptions used (TMPP 1999a pages 6.9-6 through 6.12-21). Such documentation was provided with regard to the following:

- Pollutants considered;
- Emission levels assumed for the pollutants involved;
- Dispersion modeling used to estimate potential exposure levels;
- Exposure pathways considered;
- The cancer risk estimation process;
- Hazard index calculation; and
- Characterization of project-related risk estimates.

Energy Commission staff has found these assumptions to be generally accurate and concurs with the applicant's findings with regard to the numerical public health risk estimates expressed either in terms of the hazard index for each non carcinogenic pollutant, or a cancer risk for estimated levels of the carcinogenic pollutants. These analyses were conducted to determine the potential for acute and chronic effects on body systems such as the liver, central nervous system, the immune system, kidneys, the reproductive system, the skin and the respiratory system.

The following non criteria pollutants were considered for potential to produce non cancer effects: ammonia, acetaldehyde, acrolein, benzene, 1,3 butadiene; formaldehyde, naphthalene, toluene, xylenes, propylene oxide and polycyclic aromatic hydrocarbons (PAHs). Of the criteria pollutants, only PM10 was considered as creating a potential for impacts in the problem winter months when, as noted in the Air Quality section, violations are related to air inversions in the project area. The highest measured background concentration was specified in the Air Quality section as 91 ug/m3. The following were considered with regard to a possible cancer risk: acetaldehyde, benzene, 1,3 butadiene, formaldehyde, PAHs and propylene oxide.

A hazard index value of 0.080 was calculated for combined chronic health effects of the non criteria pollutants for the individual at the maximum impact location approximately 2.5 miles in an unpopulated area south of the site boundary. A value of 0.0385 was calculated for combined acute health effects for an individual at the maximum impact location approximately 2.2 miles in an unpopulated area north-northwest of the facility. These values are significantly below the 1.0 significance level suggesting that significant non cancer health effects would be unlikely during operations with respect to non criteria pollutants. A background hazard index of 1.82 was calculated for PM10, pointing to the need to prevent further additions in the problem winter periods at issue. It is for this that specific mitigation measures are recommended in the **Air Quality** section as conditions of certification AQ-20 through AQ-22.

The highest combined cancer risk was estimated to be 0.69 in a million for an individual at the same location identified for the total hazard index for chronic effects. This risk was calculated using existing procedures, which assume that the individual will be exposed at the highest possible levels to all the carcinogenic pollutants from the project for 70 years. This risk value is much below staff's de minimis level.

In their January 10, 2000 comments on staff's PSA, the California Unions for Reliable Energy (CURE) claimed that staff did not address the potential impacts of the project's PM10 emission sin the Air Quality Section. CURE is incorrect. As noted in connection with the health effects normally addressed in staff's Public Health analyses, the PM10 issue was discussed in the Air Quality section in terms of (1) emission estimates, (2) the extent of the problem (3) main area sources, (4) trends in ambient concentrations, (5) frequency of violations, and (6) the need for specific mitigation. The applicant has since submitted a detailed project mitigation plan to offset the project's PM10 emissions while reducing the contribution from the area's wood-burning stoves and fire places (TMPP 2000). The details of this plan are presented in the **Air Quality** section along with the noted Conditions of Certification (AQ-20 through AQ-22) which will ensure implementation.

CURE also asserted without specific analysis that the project's cooling tower plume could create icy conditions on local roads, creating a severe safety problem. CURE based this assertion on discussions with local residents who, according to CURE, stated that other cooling tower plumes in the area appear to contribute to road icing in the area. We do not believe that the project would contribute significantly to any such impacts and note that its cooling towers are proposed for operation using drift eliminators with a design efficiency of 0.0006 percent (TMPG1999a, page 6.8-25). This should serve to limit the amount of project water available for any area road icing. As further mitigation in this regard, the applicant intends to reduce the use of the project's cooling towers especially during the colder periods of the year (TMPP 2000, page 4-10).

In their January 10, 2000 comments on staff PSA, the Burney Resource Group expressed concern about potential public exposure to chlorination by-products (trihalomethanes, or THMs) from the cooling tower, some of which they correctly identified as carcinogens. However, THMs are formed only in waters with significant levels of organic matter, unlike the well water and the treated wastewater to be used for the proposed project. This absence of organic matter is reflected in the representative water quality data provided for both the well water and the tertiary recycled wastewater from the Burney Water District (TMPP 1999a, pages 2-35 and 6.14-3. TMPP 2000, page 4-9). Therefore, staff does not believe that THM exposure from the project's water use would pose a significant health hazard in the area.

CUMULATIVE IMPACTS

When toxic pollutants are emitted from multiple sources within a given area, the cumulative, or additive, impacts of such emissions could, in concept, lead to significant health impacts within the population, even when such pollutants are emitted at insignificant levels from the individual sources involved. Analyses of such emissions have shown, however, that the peak impacts of such toxic pollutants are normally localized within relatively short distances from the source. Toxic pollutant emission levels beyond the point of maximum impact normally fall within background levels. Potentially significant cumulative impacts are only expected in situations where new sources are located adjacent to one other. Since no significant pollutant sources are presently proposed for the TMPP's impact area, no exposures of a cumulative nature are expected for the area.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff has determined that the construction and operation of the proposed natural gas-burning project will not pose a significant public health risk to the surrounding population with respect to the toxic pollutants considered. The applicant's PM10-specific mitigation plan should contribute significantly to the effort to deal with the area's wintertime PM10 problem. The details of this mitigation plan as presented in the **Air Quality** section along with the implementing conditions for certification (AQ-20 through AQ-22) should be adequate to assure the project's operation without significant health impacts.

RECOMMENDATIONS

Given (a) the adequacy of the applicant's mitigation measures with respect to both the project's PM10 emissions and the area's PM10 problem and, (b) staff's finding that no significant public health impacts would be associated with the toxic pollutants considered, staff does not consider further mitigation as necessary with regard to health effects. Therefore, no Health Conditions of Certification are proposed.

REFERENCES

California Air Resources Board (ARB) 1996. California Toxic Emissions Factors (CATEF) Database for Natural Gas-Fired Combustion Turbine Cogeneration.

California Air Pollution Control Officers Association (CAPCOA) 1993. Air Toxics "Hot Spots" Program, Revised 1992 Risk Assessment Guidelines. Prepared by the Toxics Committee, October 1993.

Three Mountain Power Project (TMPP) 2000. Detailed Mitigation Plan and Analysis of Impact Assessments in Resource Areas Affected by the Mitigation Plan. Submitted to the California Energy Commission, August 21, 2000.

Three Mountain Power Project 1999a. Application for Certification (99-AFC-2). Submitted to the California Energy Commission, March 3, 1999.

POWER PLANT RELIABILITY

Supplemental Testimony of Steve Baker

INTRODUCTION

In response to concerns regarding water consumption, the applicant proposes to modify the Three Mountain Power Project (TMPP) by substituting a hybrid wet-dry cooling system for the evaporative (wet) cooling system originally proposed. In addition, the existing Burney Mountain Power Project, a 10 MW biomass-fired power plant with an evaporative cooling system located adjacent to the TMPP, will be converted to use the same hybrid cooling system.

ANALYSIS

EQUIPMENT AVAILABILITY

The dry portion of the hybrid cooling system will add a large radiator and twenty fan/motor assemblies to the project (TMP 2000a, p. 3-43). The radiator, a passive component, is unlikely to hamper reliability. If one or more fan/motor units should be out of service, the remaining units would continue to function. Degradation in cooling system performance from a few failed units would be minimal. Should the dry cooling system sustain a major failure, the wet cooling system could serve as a redundant system to keep the project operating, with some additional water consumption, until repairs could be completed.

FUEL AND WATER AVAILABILITY

WATER SUPPLY RELIABILITY

By reducing the TMPP's water consumption, the substitution of a hybrid cooling system makes it less likely that sufficient water will be unavailable. This will serve to enhance plant reliability. (See the **Soil and Water Resources** portion of the FSA Part 2b.)

CONCLUSION

Any possible degradation of project reliability due to addition of the hybrid cooling system will be so small as to be insignificant. In fact, due to its effective redundancy, and to greatly reduced water demand, the hybrid system may actually enhance reliability.

REFERENCES

TMP (Three Mountain Power, LLC). 2000a. Detailed Mitigation Plan and Analysis of Impact Assessments In Resource Areas Affected by the Mitigation Plan. Submitted to the California Energy Commission, August 21, 2000.

VISUAL RESOURCES

Errata to the Testimony of David Flores

FSA Page 167, insert the following section prior to the section titled ***" BURNEY RESOURCE GROUP COMMENTS".***

WET/DRY COOLING AMENDMENT

On August 22, 2000, TMPP submitted a document titled "Detailed Mitigation Plan and Analysis of Impact Assessments In Resource Areas Affected By the Mitigation Plan". The Plan will employ a hybrid wet/dry condensing system, which consists of a water-cooled system and an air-cooled system in parallel. This section analyzes and evaluates the effects of the wet/dry condensing system and its impact in the area of visual resources.

As discussed in staff's analysis, Key Observation Point 3 (Vedder Road residential area) was the most sensitive viewpoint identified. TMPP provided a full color reproduction (Figure 3,4-1a) which shows the existing setting from the Vedder Road residential area and a simulation (Figure3, 4-1b) which shows a simulation of the project from the Vedder Road residential area, which includes the air-cooled condenser that has been included in the Mitigation Plan.

In reviewing the simulations, staff determined that the TMPP impact on the view from the Vedder Road residential area will be unaffected by the addition of the wet/dry cooling system.

Staff also evaluated the visual impacts associated with a visible cooling tower plume from the wet/dry cooling system. As provided in the Mitigation Plan, the installation of a wet/dry condensing system will reduce the operation of the wet cooling tower. During conditions of colder ambient temperatures (less than 48°F) the wet cooling tower fans would not typically operate. The fans would start operating one at a time at ambient temperatures from 48° F to 73° F. The reduced operation of the wet cooling tower fans should reduce the frequency of occurrence of visible plumes.

Due to the less frequent visible plumes from the implementation of the wet/dry condensing system, TMPP provided a revised SACTI model analysis to evaluate the cooling tower plume visibility. Staff reviewed the information provided and determined that the impact will remain less than significant.

No changes to staff's proposed Visual Resources conditions of certification are necessary as a result of the wet/dry cooling amendment.

WASTE MANAGEMENT

Testimony of Mike Ringer

INTRODUCTION

This supplemental testimony describes changes in the Three Mountain Power Project as described in the Detailed Mitigation Plan (Ogden 2000a) and their effects on the management of hazardous and nonhazardous wastes from the project. It provides additional information regarding the generation of project wastes, testing of salt cake from the zero discharge wastewater treatment system, and impacts of project wastes on landfills to be used for project wastes.

ZERO LIQUID DISCHARGE SYSTEM

As part of its Mitigation Plan to address limitations on the use of fresh water, Three Mountain Power will install a zero liquid discharge system. This system consists of a side stream softener, reverse osmosis (RO) system, brine concentrator (or evaporator), and crystallizer.

The side stream softener provides high quality water that allows the cooling tower cycles of concentration to be increased to about twenty. The RO system is used to treat cooling tower blowdown. Product water from the RO system is reused in the cooling tower and reject is sent to the brine concentrator/crystallizer system. The brine concentrator produces a highly concentrated waste blowdown (brine product) which is fed to the crystallizer feed tank. In the crystallizer, the brine becomes supersaturated in salts, which then precipitate from solution as crystals. These crystals are continuously removed by filtration and discharged from the system.

Three Mountain Power estimates that annual waste generation from the softener filter press will be about 883 tons and about 653 tons will be generated annually from the crystallizer filter press (Ogden 2000a, p. 2-50). In order to determine if the wastes might be classified as hazardous, well water from the Burney Water District was used in a laboratory simulation of the zero liquid discharge system (Ogden 2000a, p. 2-50). Analyses of the solid wastes similar to those that would be generated from the softener as well as the crystallizer indicate that all metals of concern were below California regulatory limits that define hazardous waste (Ogden 2000a, Appendix C). Because the Burney Water District will provide reclaimed wastewater to the project to be used as process water, additional laboratory analysis was performed on wastewater discharged to the District's percolation ponds. Because no significant presence of metals or hazardous substances were detected (Ogden 2000a, Appendix B), use of reclaimed wastewater would not alter the classification of the waste.

Although the solid wastes generated from the softener and crystallizer would not be classified as hazardous, they would still be considered a California designated waste due to their high salt content. The category of designated waste includes nonhazardous waste that contains pollutants that, under ambient environmental conditions at a waste management unit, could be released in concentrations that could exceed applicable water quality objectives or affect the beneficial uses of waters of the state (Cal. Code Regs., tit. 27, § 20210). Designated wastes are required to be disposed of at Class I or Class II disposal sites. Three Mountain Power has identified two suitable disposal sites in the project vicinity, and has proposed to use the Lockwood Regional Landfill in Lockwood, Nevada, which currently accepts filter cake from other facilities. Lockwood currently accepts about 5800 tons per day, and has a remaining life of about 27 years at its current permitted area of 555 acres. Additionally, it has about 1550 acres available for future expansion. Wastes from Three Mountain Power would account for about 0.1 percent of the annual wastes accepted at Lockwood and would have no significant impact on either the daily operating capacity or remaining life of the facility. Staff proposed the addition of Condition of Certification WASTE-7 which requires Three Mountain Power to dispose of project softener and crystallizer filter wastes at Lockwood.

Construction and operation of the zero liquid discharge system would not have any significant effects on any of the other waste streams generated at Three Mountain.

CONDITION OF CERTIFICATION

WASTE-7 The project owner shall dispose of filter cakes from the zero liquid discharge system softener and crystallizer at the Lockwood Regional Landfill in Lockwood, Nevada, or a CPM approved alternative site.

Verification: The project owner shall maintain records of waste shipments to the Lockwood Regional Landfill and retain receipts or manifests from the landfill on site. The receipts shall be made available to the CEC CPM upon request.

REFERENCES

Ogden 2000a. Detailed Mitigation Plan and Analysis of Impact Assessments in Resource Areas Affected by the Mitigation Plan. Three Mountain Power, LLC. AFC-99-02. Submitted to the California Energy Commission. August 21.